U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-285 172

Field Tests of Industrial Stoker Coal-Fired Boilers for Emissions Control and Efficiency Improvement - Site A

KVB, Inc, Minneapolis, Minn

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, N C

Jul 78

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-600/7-78-136a		PB285172

4. TITLE AND SUBTITLE	5. REPORT DATE
Field Tests of Industrial Stoker Coal-fired Boilers for Emissions Control and Efficiency Improvement--Site A	July 1978
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
J.E. Gabrielson, P.L. Langsjoen, and T.C. Kosvic	
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
KVB, Inc. 600 South County Road 18 Minneapolis, Minnesota 55426	EHE624
	11. CONTRACT/GRANT NO.
	EPA-IAG-D7-E681 and DOE-EF-77-C-01-2609
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
EPA, Office of Research and Development * Industrial Environmental Research Laboratory Research Triangle Park, NC 27711	Final; 6-12/77
	14. SPONSORING AGENCY CODE
	EPA/600/13 and DOE

15. SUPPLEMENTARY NOTES IERL-RTP project officer is R.E. Hall. (*)Cosponsors are DOE (W.T. Harvey, Jr.) and the American Boiler Manufacturers Assoc.

16. ABSTRACT The report gives results of field measurements made on a 300,000 lb/hr spreader stoker boiler. The effect of various parameters on boiler emissions and efficiency was studied. Parameters studied included overfire air, flyash reinjection, excess air, boiler load, and fuel properties. Measurements included gaseous emissions, particulate emissions, particle size distribution of the flyash, and combustible content of the ash. Gaseous emissions measured were excess O2, CO2, CO, NO, SO2, and SO3. Sample locations included the boiler outlet, multiclone outlet, electrostatic precipitator outlet, and wet sulfur scrubber outlet. In addition to test results and observations, the report describes the facility tested, coals fired, test equipment, and procedures.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Improvement	Air Pollution Control	13B
Boilers	Efficiency	Stationary Sources	13A
Combustion	Flue Gases	Combustion Modification	21B
Coal	Fly Ash	Spreader Stokers	21D
Field Tests	Particle Size	Particulate	14B
Dust	Nitrogen Oxides	Overfire Air	11G 07B
Stokers	Sulfur Oxides	Flyash Reinjection	

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS (This Report)	21. NO. OF PAGES
Unlimited	Unclassified	106
	20. SECURITY CLASS (This page)	22. PRICE
	Unclassified	A06-A01

EPA Form 2220-1 (9-73)

ABMA
DoE
EPA

American Boiler Manufacturers Association
1500 Wilson Boulevard
Arlington VA 22209

PB 285 172

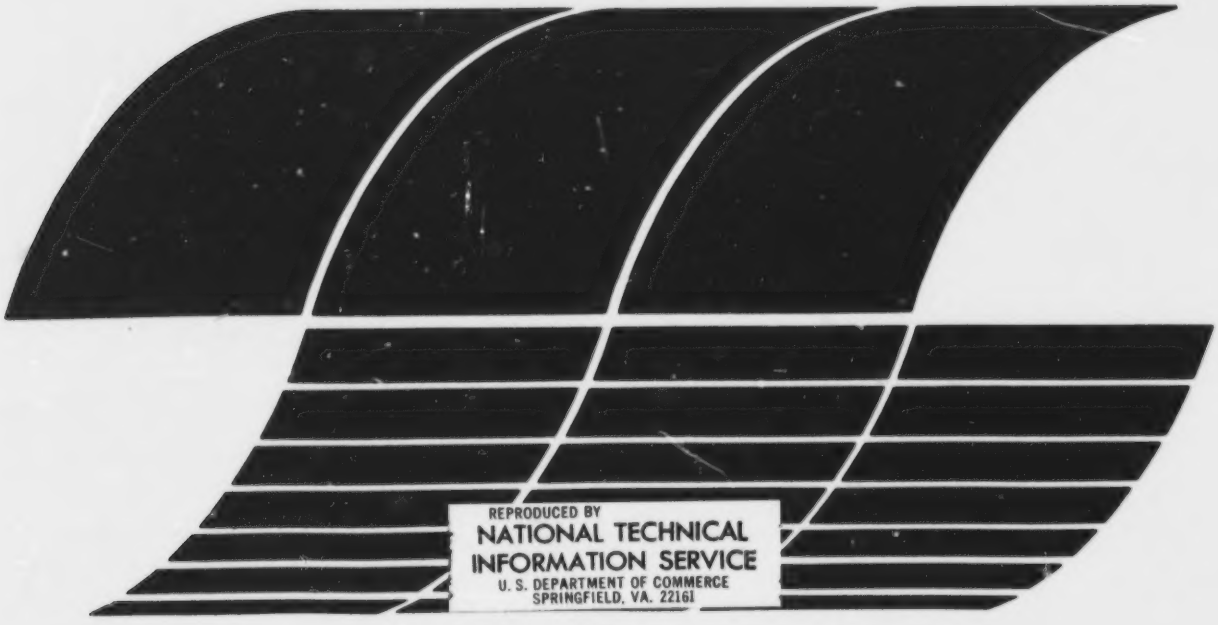
United States Department of Energy
Division of Power Systems
Energy Technology Branch
Washington DC 20545

U.S. Environmental Protection Agency
Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park NC 27711

EPA-600/7-78-136a
July 1978

Field Tests of Industrial Stoker Coal-fired Boilers for Emissions Control and Efficiency Improvement - Site A

Interagency Energy/Environment R&D Program Report



REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

REVIEW NOTICE

This report has been reviewed by the participating Federal Agencies, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Government, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

EPA-600/7-78-136a
July 1978

Field Tests of Industrial Stoker Coal-fired Boilers for Emissions Control and Efficiency Improvement - Site A

by

J.E. Gabrielson, P.L. Langsjoen, and T.C. Kosvic

KVB, Inc.
600 South County Road 18
Minneapolis, Minnesota 55426

IAG/Contract Nos. IAG-D7-E681 (EPA), EF-77-C-01-2609 (DoE)
Program Element No. EHE624

Project Officers: Robert E. Hall (EPA) and William T. Harvey, Jr. (DoE)

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

U.S. DEPARTMENT OF ENERGY
Division of Power Systems/Energy Technology Branch
Washington, DC 20545

and

AMERICAN BOILER MANUFACTURERS ASSOCIATION
1500 Wilson Boulevard
Arlington, VA 22209

1a

ACKNOWLEDGMENTS

The authors wish to express their appreciation for the assistance and direction given the program by project monitors W. T. (Bill) Harvey of the United States Department of Energy (DOE) and R. E. (Bob) Hall of the United States Environmental Protection Agency (EPA). Thanks are due to their agencies, DOE and EPA, for co-funding the program.

We would also like to thank the American Boiler Manufacturers Association (ABMA) staff members W. B. (Bill) Marx, Executive Director, W. H. (Bill) Axtman, Assistant Executive Director, and B. C. (Ben) Severs, Project Manager, and the members of their Stoker Technical Committee chaired by W. B. (Willard) McBurney of the McBurney Corporation for providing support through their time and travel to manage and review the program. The participating committee members listed alphabetically are as follows:

F. C. Belsak	Island Creek Coal
R. D. Bessette	Island Creek Coal
T. Davis	Combustion Engineering
J. Dragos	Consolidation Coal
T. G. Healey	Peabody Coal
W. B. Hoffmann	Hoffmann Combustion Engineering Co.
N. H. Johnson	Detroit Stoker
K. Luuri	Riley Stoker
J. Mullan	National Coal Association
E. A. Nelson	Zurn Industries
E. Poitrass	The McBurney Corporation
P. E. Ralston	Babcock and Wilcox
D. C. Reschley	Detroit Stoker
R. A. Santos	Zurn Industries
W. Sisken	U.S. Department of Energy

We would also like to recognize the KVB engineers and technicians who spend most of their time in the field, often under adverse conditions, testing the boilers and gathering data for this program. Those involved to date are George Moilanen, Jim Burlingame, Russ Parker, Jon Cook, John Rech, and Jim Demont.

Finally, our gratitude goes to the host boiler facilities who invited us to test their boilers. At their request, these facilities will remain anonymous to protect their own interests. Without their cooperation and assistance this program would not have been possible.

TABLE OF CONTENTS

Section			Page
Acknowledgments			ii
List of Figures			iv
List of Tables			v
1.0	INTRODUCTION		1
2.0	EXECUTIVE SUMMARY		3
3.0	DESCRIPTION OF FACILITY TESTED AND COALS FIRED		17
	3.1	Boiler A Description	17
	3.2	Coals Utilized	26
4.0	TEST EQUIPMENT AND PROCEDURES		28
	4.1	Gaseous Emissions Measurements	28
	4.2	Gaseous Emission Sampling Techniques	33
	4.3	Sulfur Oxides (SOx) Measurement and Procedure	35
	4.4	Particulates Measurement and Procedures	39
	4.5	Particle Size Distribution Measurement and Procedure	39
	4.6	Coal Sampling and Analysis Procedures	42
	4.7	Ash Collection and Analysis for Combustibles	43
	4.8	Boiler Efficiency Evaluation	44
	4.9	Modified Smoke Spot Number	45
	4.10	Corrosion/Deposition Analysis	46
	4.11	Trace Species Measurement	48
	4.12	Flyash Resistivity Measurement	50
5.0	TEST RESULTS AND OBSERVATIONS		51
	5.1	Overfire Air	51
	5.2	Flyash Reinjection	56
	5.3	Excess Air	60
	5.4	Boiler Load	70
	5.5	Coal Properties	72
6.0	SPECIAL TESTS		79
	6.1	Particle Size Distribution	79
	6.2	Size Segregation of Combustible Material	85
	6.3	Efficiency of Pollution Control Equipment	85
	6.4	Modified Smoke Spot Number	87
	6.5	Corrosion Probe Study	91
	6.6	Flyash Resistivity	94
	6.7	Source Assessment Sampling System	94
	APPENDIX		96

LIST OF FIGURES

Figure		Page
3-1	BOILER A SECTIONAL SIDE ELEVATION	18
3-2	BOILER A SCHEMATIC	19
3-3	SAMPLE PLANE GEOMETRY	20
3-4	SAMPLE PLANE GEOMETRY	21
4-1	FLOW SCHEMATIC OF MOBILE FLUE GAS MONITORING LABORATORY	34
4-2	SOx SAMPLE PROBE CONSTRUCTION	36
4-3	SULFUR OXIDES SAMPLING TRAIN	37
4-4	PARTICULATE SAMPLING TRAIN	38
4-5	BRINK CASCADE IMPACTOR SAMPLING TRAIN SCHEMATIC	41
4-6	FIELD SERVICE TYPE SMOKE TESTER	45
4-7	REFLUX BOILER CORROSION PROBE	47
4-8	SOURCE ASSESSMENT SAMPLING SYSTEM FLOW DIAGRAM	49
5-1	PARTICULATE LOADING VS OVERFIRE AIR	53
5-2	PARTICULATE LOADING VS FLYASH REINJECTION	57
5-3	PARTICULATE LOADING VS EXCESS OXYGEN AT MECHANICAL COLLECTOR OUTLET	63
5-4	CARBON MONOXIDE VS EXCESS OXYGEN AND LOAD	64
5-5	NITRIC OXIDE VS EXCESS OXYGEN AND LOAD	65
5-6	NITRIC OXIDE TRENDS VS EXCESS OXYGEN AND LOAD	67
5-7	DRY GAS LOSS VS EXCESS OXYGEN, LOAD AND COAL	68
5-8	PARTICULATE LOADING AT THE MULTICLONE OUTLET VS GRATE HEAT RELEASE	71
5-9	AVERAGE AND STANDARD DEVIATION OF 12 KEMMERER COAL SIEVE ANALYSIS VS ABMA RECOMMENDED LIMITS FOR SPREADER STOKERS	74
5-10	AVERAGE AND STANDARD DEVIATION OF 6 CONSOLIDATION COAL SIEVE ANALYSIS VS ABMA RECOMMENDED LIMITS FOR SPREADER STOKERS	75
5-11	COMPARISON OF TWO COAL SAMPLING LOCATIONS FOR SIEVE TESTING	77
6-1	COMPOSITE OF ALL PARTICLE SIZING TESTS AT SITE A	81
6-2	COMPARISON OF PARTICLE SIZING TECHNIQUES	82
6-3	COMPARISON OF PARTICLE SIZING TECHNIQUES	83
6-4	MODIFIED SMOKE SPOT NUMBER VS PARTICULATE LOADING	88
6-5	MODIFIED SMOKE SPOT NUMBER VS COMBUSTIBLE LOADING	89
6-6	CORROSION RATE VS TIME	93

LIST OF TABLES

Table		Page
2-1	EMISSION DATA SUMMARY	7
2-2	PARTICULATE EMISSIONS SUMMARY	8
2-3	SUMMARY OF HEAT LOSS ESTIMATES	9
2-4	SUMMARY OF PERCENT COMBUSTIBLES IN REFUSE	10
2-5	COAL SIZING SUMMARY	11
2-6	FUEL ANALYSIS SUMMARY - STANSBURY COAL	12
2-7	FUEL ANALYSIS SUMMARY - KEMMERER COAL	13
2-8	FUEL ANALYSIS SUMMARY - CONSOLIDATION COAL	14
2-9	MINERAL ANALYSIS OF ASH	15
2-10	SUMMARY OF STEAM FLOWS AND HEAT RELEASE RATES	16
3-1	BOILER A DESIGN DATA	23
3-2	BOILER A DESIGN PERFORMANCE SUMMARY	24
3-3	ULTIMATE ANALYSIS OF COAL UPON WHICH PERFORMANCE DATA IS BASED	25
3-4	AS FIRED PROXIMATE ANALYSIS OF COALS TESTED IN BOILER A	26
3-5	TEST NUMBERS CORRESPONDING TO COALS FIRED	27
5-1	EFFECT OF OVERFIRE AIR ON EMISSIONS AND EFFICIENCY	52
5-2	EFFECT OF OVERFIRE AIR ON GASEOUS EMISSIONS	55
5-3	EFFECT OF FLYASH REINJECTION ON EMISSIONS & EFFICIENCY	59
5-4	EFFECT OF EXCESS O_2 ON COMBUSTIBLES IN REFUSE	61
5-5	COAL PROPERTIES CORRECTED TO A CONSTANT 10^6BTU BASIS	72
5-6	SULFUR BALANCE SUMMARY	78
6-1	VARIATION OF PERCENT COMBUSTIBLES WITH PARTICLE SIZE	85
6-2	EFFICIENCY OF POLLUTION CONTROL EQUIPMENT	86
6-3	MODIFIED SMOKE SPOT DATA	90
6-4	CORROSION RATE DATA	92
6-5	SASS TESTS RUN AT SITE A	94

1.0 INTRODUCTION

In recent years the vast majority of industrial boiler installations have been packaged or shop assembled gas and oil fired boiler units which could be purchased and installed at substantially lower costs than conventional coal burning boiler-stoker equipment. Because of the decline in this market area, little or no work has been done in recent years to improve specification data and information made available to Consulting Engineers and Purchasers of coal burning boiler-stoker equipment. The current implementation of more rigid air pollution regulations has made it difficult for many coal burning installations to comply with required stack emission limits, and this has become a further negative influence on coal burning installations.

The American Boiler Manufacturers Association (ABMA), in conjunction with the Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA), have established a field test program to address this problem. KVB, Inc., a combustion consulting firm, is performing the testing. The objective of this program is to produce information which will increase manufacturers' ability to design and fabricate stoker boilers which are an economical and environmentally satisfactory alternative to importation and combustion of expensive oil. In order to do this, it is necessary to define stoker boiler designs which will provide efficient operation with minimum gaseous and particulate emissions, and define what those emissions are in order to facilitate preparation of attainable national emission standards for industrial size, coal-fired units.

Further objectives are to: provide assistance to stoker boiler operators in planning for coal supply contracts; refine application of existing pollution control equipment with special emphasis on performance; and contribute to the design of new pollution control equipment.

In order to meet these objectives, it is necessary to determine emissions and efficiency as functions of changes in coal analysis and sizing, degree of flyash reinjection, overfire air admission, ash handling, grate size, etc., for various boiler, furnace and stoker designs.

This report is the Final Technical report for the first of many boilers to be tested under the program described above. It contains a description of the facility tested, the coals fired, the test equipment and procedures and the results and observations of testing. A companion volume to this report contains the original "raw" data sheets from the forty tests conducted on this boiler. As a compilation of all the data obtained at this test site, it acts as a research tool for further data reduction and analysis as new areas of interest are uncovered in subsequent testing.

At the completion of this program, a Final Technical Report will tie together the test results from all sites tested. This final report will provide the technical basis for the ABMA publication on "Design and Operating Guidelines for Industrial Stoker Firing," and will be available to interested parties through the ABMA, EPA, or DOE.

To protect the interests of the host boiler facilities, each test site in this program has been given a letter designation. As the first site tested, this is the Final Technical Report for Test Site A under the program entitled, "A Testing Program to Update Equipment Specifications and Design Criteria for Stoker Fired Boilers."

2.0 EXECUTIVE SUMMARY

This Section outlines the major conclusions drawn from the test program at Site A. Comments are organized into groups according to the parameter studied.

Overfire Air. Increasing the overfire air effectively increased fuel-air mixing in the flame zone by inducing turbulence. The result was a significant reduction in carbon carryover. Increasing the overfire air pressure from four to ten inches water pressure while maintaining excess air constant resulted in:

- 25-50% reduction in particulate loading at the boiler outlet due primarily to a reduction in combustible content of the ash.
- 0.8-2% increase in combustion efficiency as a result of reduced carbon carryover.
- Reduction in carbon monoxide (CO) concentrations under those conditions (low excess O_2) where significant concentrations of CO are formed.
- An average 5% or 16 ppm reduction in nitric oxide (NO) emissions. A reduction which is not statistically significant.

Flyash Reinjection from the multiclone hopper resulted in an increase in combustion efficiency but also resulted in an increase in particulate loading at the boiler outlet. Three sets of tests with and without reinjection were run with the following results:

- Combustion efficiency increased between 1.5 and 2.5% when flyash was reinjected. This was due to burnout of combustibles in the flyash.
- Particulate loading at the boiler outlet increased between 22 and 39% when flyash was reinjected. This was due to reentrainment of the reinjected ash.
- There were no significant changes in concentrations of nitric oxide or carbon monoxide due to reinjection.
- Clinkering on the grate due to reinjection was not observed to be a problem. However, these tests were short in duration and may not give the full picture.

Excess air reduction improved boiler efficiency and emissions. A one percent drop in excess oxygen from six to five percent resulted in:

- A reduction in particulate loading at the multiclone outlet of 5, 17 and 21% in three test sets, and a reduction of 8% in one test set at the boiler outlet.
- A reduction in combustible heat losses of 0.15, 0.55 and 0.83% in three test sets, and an average decrease in dry gas loss of 0.8%.
- An average reduction in nitric oxide emissions of 55 ppm.

Boiler A was able to operate satisfactorily at 4.5 to 5.0% excess oxygen (25 to 30% excess air) between 60 and 80% of load burning all three coals tested. Lower loads required increased excess air; higher loads were not tested.

Boiler Load. In the range of 60 to 80% of maximum continuous capacity, a ten percent increase in load brought about:

- A ten percent increase in particulate emissions at the boiler outlet.
- An average 45 ppm increase in nitric oxide emissions.

Fuel Properties. Three low sulfur western coals were tested. Each varied in moisture, ash and sulfur content. Their impact on emissions and efficiency were as follows:

- A three percent ash coal from Kemmerer Coal Company produced 1/3 less particulates at the boiler outlet than an eight percent ash coal from Consolidation Coal Co. Both coals had similar ash fusion temperatures and sizings.
- One percent or less of the fuel sulfur was retained in the bottom ash. Between one and four percent of the fuel sulfur was retained in the flyash. The remaining sulfur was emitted as SO_2 and SO_3.
- Coals averaging 60% through a 1/4 inch square mesh screen were successfully fired on a day-to-day basis at Test Site A. This is finer than the 20% to 50% range recommended for spreader stokers by the ABMA.

- The 13% moisture Consolidation coal burned 1.9% more efficiently than the 19% moisture Kemmerer coal due to the 6% difference in moisture.

Particle Size Distribution was measured at the boiler outlet, the multiclone outlet and the electrostatic precipitator outlet. Four sizing techniques were used. The Brink Cascade Impactor was unacceptable as a method for sizing particles at the boiler outlet of this spreader stoker. SASS cyclone, BAHCO classifier and Coulter Counter were acceptable methods but each had limitations. The results are presented in Figure 6-1.

Combustibles in Ash and the resultant heat losses were found to be as follows on the average:

Bottom ash:	0.8% Combustibles	0.03% Heat Loss
Multiclone Catch:	66% Combustibles	2.00% Heat Loss
Flyash Passing Multiclone:	30% Combustibles	0.50% Heat Loss

The combustible content of the ash is related to particle size with large particles containing a larger percent of the combustibles.

Efficiency of Pollution Control Equipment. The plants physical layout was such that, for sampling purposes, the mechanical collector could not be isolated from the air heater's settling hopper for determining its collection efficiency. The two combined removed 94% of the boiler outlet particulates. The ESP removed 97-98% of the remaining particulates. The sulfur scrubber removed 60% of the SOx entering it. Its design efficiency was 90%.

Modified Smoke Spot Number did not correlate with either particulate loading or combustible loading at the boiler outlet.

Corrosion Probe Data was inconclusive. Corrosion coupons were not exposed long enough to produce repeatable or meaningful corrosion/erosion rates.

Flyash Resistivity. No data was obtained due to application problems with the Wahlco resistivity device.

Source Assessment Sampling System. SASS test results will be reported on under separate cover at the conclusion of the testing portion of this program.

The following summary tables present reduced data from the testing performed at Site A:

Table	Title
2-1	Emission Data Summary
2-2	Particulate Emission Summary
2-3	Summary of Heat Loss Estimates
2-4	Summary of Percent Combustibles in Refuse
2-5	Coal Sizing Summary
2-6	Fuel Analysis Summary - Stansbury Coal
2-7	Fuel Analysis Summary - Kemmerer Coal
2-8	Fuel Analysis Summary - Consolidation Coal
2-9	Mineral Analysis of Ash
2-10	Summary of Steam Flows and Heat Release Rates

TABLE 2-1

EMISSION DATA SUMMARY
TEST SITE A

Test No.	Date	Load %	Coal	Type of Test	Conditions	O_2 % dry	CO ppm dry	NO ppm dry	SO_2 ppm dry	SO_3 ppm dry	Excess Air %	Part lb/10^6BTU
1	8/09/77	64	S	SOx mech out	- as found	4.9	180	343	768	2	29	
2A	8/10/77	59	S	Vary excess air	- as found	4.3	86	345			25	
2B					- reduce	3.6	126	316			20	
2C					- reduce	2.7	266	285			14	
2D					- reduce	1.7	1072	256			8	
2E					- raise	3.7	127	302			21	
2F					- raise	4.4	174	325			26	
2G					- raise	5.1	91	358			31	
2H					- raise	5.9	95	400			38	
3	8/11/77	61	S	Part mech out	- low air	4.1	219	312			23	0.58
4	8/17/77	60	S	Part mech out & Brink	- high air	6.3	77	497			41	0.65
5	8/18/77	72	S	Part mech out	- low air	4.1	536	385			23	0.66
6	8/18/77	70	S	Part mech out	- high air	5.8	392	414			37	0.95
7A	8/19/77	68	S	Vary excess air	- as found	5.2	171	399			32	
7B					- reduce	4.0	657	365			23	
7C					- reduce	3.4	818	327			18	
7D					- reduce	3.0	1050	320			16	
7E					- raise	5.0	137	394			30	
8A	8/20/77	65	S	SOx mech out	- as found	4.8	141	417	749	5	29	
8B		52		SOx stack	- as found	6.8	53	451	304	0	46	
9	8/23/77	61	S	SOx mech out	- as found	4.9	81	367	793	3	29	
10	8/24/77	37	S	Part mech out	- as found	9.9	83	554			85	0.54
11A	8/24/77	41	S	Vary excess air	- low air	7.8	41	490			57	
11B					- raise	8.0	56	506			59	
11C					- raise	8.5	72	541			65	
11D					- raise	9.1	99	584			73	
11E					- raise	9.5	102	597			79	
11F					- reduce	7.5	47	448			53	
12	8/24/77	45	S	SOx mech out	- as found	6.1	46	414	790	5	39	
13A	8/25/77	77	S	Vary excess air	- as found	5.2	912	502			31	
13B					- reduce	3.7	2000+	406			20	
14A	8/26/77	74	S	Part mech out	- high air	5.4	150	455			33	0.66
14B		69		Brink mech out	- as found	5.6	95	440			35	
15	8/27/77	73	S	Part mech out	- low air	4.5	264	428			26	0.57
16	8/30/77	59	SK	Simultaneous Part across ESP	- as found	6.1	104	473			39	0.51/0.017
17	8/31/77	52	SK	Simultaneous Part across Scrubber	- as found	6.3	83	439			41	0.019/0.013
18A	9/11/77	46	S	SOx mech out	- as found	7.4	62	386	886	10	52	
18B				SOx stack	- as found	7.1	52	409	313	5	49	
19	9/12/77	44	S	Brink mech out	- as found	6.8	44	386			46	
20	9/14/77	42	K	SOx mech out & Brink ESP out	- as found	5.3	44	306	1086	11	33	
21	9/23/77	82	K	Part blr out	- w/o reinjection	4.5	998	392			26	12.1
22	9/23/77	83	K	Part blr out	- with reinjection	4.1	1600	362			23	16.6
23	9/24/77	59	K	Part blr out	- with reinjection	4.4	104	388			26	11.7
24	9/24/77	59	K	Part blr out	- w/o reinjection	4.8	150	370			29	8.4
25A	10/05/77	74	K	Gaseous only	- 9" O.F.A.	5.0	450	439			30	
25B				Gaseous only	- 3" O.F.A.	4.4	802	423			25	
26A	10/06/77	70	K	Part blr out	- as found	5.1	413	446			31	9.8
26B		74		Part mech out	- as found	4.6	405	416			27	0.60
27	10/04/77	81	K	SASS blr out	- as found	4.2	1022	388			24	
28	10/10/77	84	K	Part blr out	- 4" O.F.A.	3.9	1076	408			22	20.5
29	10/10/77	85	K	Part blr out	- 9" O.F.A.	3.8	480	398			21	15.4
30	10/13/77	80	K	Brink blr out	- as found	4.0	383	460			23	
31A	10/14/77	53	K	Vary overfire air	- all O.F.A. 5"	2.6	181	196			14	
31B					- LF 2" others 5"	2.6	293	196			14	
31C					- LF 10" others 5"	2.6	117	201			14	
31D		56			- all O.F.A. 5"	3.6	233	243			20	
31E					- UF 2" others 5"	3.5	231	244			20	
31F					- UF 10" others 5"	3.5	231	239			20	
32	10/15/77	83	K	SASS blr out	- as found	5.2	219	497			32	
34A	10/29/77	76	C	SASS, part, SOx blr out	- 10.5" O.F.A.	5.9	300	353	504	10	38	11.9
34B				SASS, part, SOx ESP out	- 10.5" O.F.A.	*6.5	483	315	479	12	43	0.058
35A	10/30/77	76	C	SASS, Part, SOx blr out	- 5" O.F.A.	6.0	313	394	410	7	38	20.5
35B				SASS, Part, SOx ESP out	- 5" O.F.A.	*6.4	243	382	353	2	42	0.030
36	11/01/77	80	C	Part blr out	- w/o reinjection	4.7	2000	344			27	18.5
37	11/01/77	67	C	Part blr out	- with reinjection	5.1	276	347			31	22.5
38	11/02/77	59	C	Part blr out	- 10.5" O.F.A.	4.7	61	313			28	6.3
39	11/02/77	63	C	Part blr out	- 3.0" O.F.A.	4.9	670	335			29	13.3
40	11/11/77	64	K	SASS blr out	- as found	6.9	108	546			47	

NOTES: Gaseous data for tests 1-20 obtained at the mechanical collector outlet
Gaseous data for tests 21-40 obtained at the boiler outlet
* Gaseous data for tests 34B and 35B obtained at the ESP outlet
Particulate, SO_2 and SO_3 data obtained at location specified under "Type of Test"
Coal supplier: S = Stansbury, K = Kemmerer, C = Consolidation Coal Co.

TABLE 2-2

PARTICULATE EMISSIONS SUMMARY
TEST SITE A

Test No	% Load	% O_2	Sample Location	EMISSIONS lb/10^6 BTU	EMISSIONS gr/SCF	EMISSIONS lb/hr	Velocity ft/sec	Flow SCF/sec
3	61	4.1	Mech Outlet	0.582	0.329	153	33.25	905
4	60	6.3	Mech Outlet	0.646	0.317	164	37.34	1006
5	72	4.1	Mech Outlet	0.660	0.373	194	38.54	1014
6	70	5.8	Mech Outlet	0.948	0.481	271	41.95	1095
10	37	9.9	Mech Outlet	0.537	0.199	86	29.85	837
14	74	5.4	Mech Outlet	0.663	0.345	196	42.05	1104
15	73	4.5	Mech Outlet	0.572	0.315	174	41.16	1071
16A	59	6.1	Mech Outlet	0.512	0.259	134	37.52	1004
16B	59	6.1	ESP Outlet	0.0166	0.0076	4.04	67.13	1032
17A	52	6.3	ESP Outlet	0.0194	0.0090	4.25	62.12	915
17B	52	6.3	Stack	0.0128	0.0057	2.82	33.48	958
21	82	4.5	Blr Outlet	12.12	6.82	4275	34.21	1220
22	83	4.1	Blr Outlet	16.63	9.58	6719	36.96	1365
23	59	4.4	Blr Outlet	11.67	6.60	3098	23.68	913
24	59	4.8	Blr Outlet	8.43	4.65	2288	24.92	956
26A	70	5.1	Blr Outlet	9.77	5.31	3034	29.95	1111
26B	74	4.6	Mech Outlet	0.600	0.335	201	45.78	1168
28	84	3.9	Blr Outlet	20.48	11.93	8026	37.32	1308
29	85	3.8	Blr Outlet	15.41	9.03	5839	35.95	1258
34A	76	5.9	Blr Outlet	11.89	6.10	3740	32.15	1193
34B	76	5.9	ESP Outlet	0.0576	0.0283	16.0	78.97	1095
35A	76	6.0	Blr Outlet	20.48	10.44	6705	34.65	1249
35B	76	6.0	ESP Outlet	0.0296	0.0146	9.0	89.32	1220
36	79	4.7	Blr Outlet	18.51	10.23	5819	30.21	1106
37	87	5.1	Blr Outlet	22.54	12.15	7181	32.11	1149
38	59	4.7	Blr Outlet	6.29	3.48	1568	22.88	878
39	60	4.9	Blr Outlet	13.26	7.24	3223	22.36	866

TABLE 2-3

SUMMARY OF HEAT LOSS ESTIMATES
TEST SITE A

	Test No.	Dry Gas	Moisture in Fuel	H_2O from Combustion of H_2	Combustibles in Mech Collected Ash	Combustibles in Flyash	Combustibles in Bottom Ash	Total Combustibles in Refuse	Radiation From Boiler	Radiation From Precipitator	Unmeasured	Total Losses	Efficiency
STANSBURY COAL	3	6.94	1.64	4.40	1.12	0.26	0.03	1.41	0.56	0.70	1.50	17.15	82.85
	4	9.00	1.63	4.38	1.39	0.33	0.03	1.75	0.57	0.70	1.50	19.53	80.47
	5	7.54	1.63	4.41	1.73	0.41	0.03	2.17	0.47	0.70	1.50	18.42	81.58
	6	8.75	1.63	4.39	2.87	0.68	0.03	3.58	0.48	0.70	1.50	21.03	78.97
	10	10.73	1.61	4.31	0.82	0.19	0.04	1.05	0.50	0.70	1.50	20.40	79.60
	15	7.72	1.63	4.37	1.51	0.36	0.03	1.90	0.46	0.70	1.50	18.28	81.72
KEMMERER COAL	21	7.10	2.38	4.23	2.30	0.57	0.01	2.88	0.41	0.70	1.50	19.20	80.80
	22	7.76	2.40	4.24	0.00	0.72	0.01	0.73	0.40	0.70	1.50	17.73	82.27
	23	6.78	2.36	4.18	0.00	0.35	0.01	0.36	0.58	0.70	1.50	16.46	83.54
	24	7.00	2.36	4.18	1.46	0.36	0.01	1.83	0.58	0.70	1.50	18.15	81.85
	26	8.49	2.39	4.22	1.34	0.34	0.04	1.72	0.46	0.70	1.50	19.48	80.52
	28	8.52	2.41	4.27	3.83	0.95	0.02	4.80	0.40	0.70	1.50	22.60	77.40
	29	8.81	2.31	4.29	2.26	0.56	0.00	2.82	0.40	0.70	1.50	20.83	79.17
CONSOLIDATION COAL	34	7.57	1.46	4.13	1.74	0.43	0.05	2.22	0.44	0.70	1.50	18.02	81.98
	35	8.02	1.47	4.16	3.18	0.79	0.09	4.06	0.44	0.70	1.50	20.35	79.65
	36	6.95	1.46	4.13	2.66	0.66	0.03	3.35	0.44	0.70	1.50	18.53	81.47
	37	7.41	1.46	4.14	0.00	0.82	0.04	0.86	0.39	0.70	1.50	16.46	83.54
	38	6.07	1.43	4.05	1.00	0.25	0.01	1.26	0.58	0.70	1.50	15.59	84.41
	39	6.13	1.43	4.05	1.53	0.38	0.15	2.06	0.57	0.70	1.50	16.44	83.56

TABLE 2-4

SUMMARY OF PERCENT COMBUSTIBLES IN REFUSE
TEST SITE A

	Test No.	Boiler Outlet	Multiclone Outlet	Multiclone Catch	Bottom Ash
STANSBURY COAL	3	--	26.3	--	--
	4	--	29.2	--	--
	5	--	37.6	--	--
	6	--	39.1	--	--
	10	--	20.1	--	--
	14	--	--	--	0.74
	15	--	37.6	--	--
KEMMERER COAL	16A	--	21.4	--	0.12
	17	--	--	--	0.28
	21	72.1	--	76.70	--
	22	58.4	--	--	--
	23	43.7	--	--	0.26
	24	60.8	--	--	0.53
	26A	52.3	--	58.81	1.87
	26B	--	30.8	74.17	0.17
	28	65.8	--	80.59	--
	29	54.6	--	58.73	0.00
CONSOLIDATION COAL	34A	--	--	66.6	0.82
	35A	--	--	70.0	1.66
	36	60.1	--	68.45	--
	37	65.6	--	--	--
	38	61.3	--	54.71	0.23
	39	47.2	--	48.06	2.80
AVERAGE		58.4	30.3	66.00	0.79

TABLE 2-5

COAL SIZING SUMMARY
TEST SITE A

% Passing:	1"	1/2"	1/4"	#8	#16
TEST NO.					
21	96	78	45	23	15
22	97	87	70	40	26
23	99	83	49	23	13
24	98	88	67	38	22
26A	98	78	47	23	14
26B	99	89	66	35	22
27	99	88	64	33	20
28	96	74	44	22	14
29	97	76	49	26	16
30	95	77	52	28	17
32	99	91	72	38	23
34	98	82	53	27	17
35	98	82	52	32	19
36	95	75	50	27	17
37	97	88	70	42	27
38	98	90	74	41	28
39	97	87	72	44	28
40	97	86	68	43	28

TABLE 2-6

FUEL ANALYSIS SUMMARY - TEST SITE A - STANSBURY COAL

TEST NO.	1	5	8	9	10	12	14	15	18	19	AVG.
PROXIMATE (as rec.)											
% Moisture	14.21	15.33	13.10	14.57	13.70	13.36	14.61	13.56	15.05	15.64	14.31
% Ash	7.00	5.21	5.79	5.95	6.70	5.70	4.49	6.13	5.90	8.04	6.09
% Volatile	33.96	34.29	35.18	34.79	34.33	35.15	35.03	35.69	34.72	33.97	34.71
% Fixed Carbon	44.83	45.27	45.93	44.69	45.27	45.79	45.87	44.62	44.33	42.35	44.90
BTU/lb	10365	10588	10838	10637	10505	10548	10780	10567	10538	10107	10547
% Sulfur	1.05	1.02	0.97	0.91	0.92	0.88	0.90	0.86	0.88	0.92	0.93
ULTIMATE (as rec.)											
% Moisture	14.21				13.70						
% Carbon	60.64				60.30						
% Hydrogen	4.24				4.08						
% Nitrogen	1.01				0.96						
% Chlorine	0.00				0.02						
% Sulfur	1.05				0.92						
% Ash	7.00				6.70						
% Oxygen (diff.)	11.85				13.32						
ASH FUSION (reducing)											
Initial Deformation					2000						2000
Soft. (H=W)					2190						2190
Soft. (H=1/2W)					2240						2240
Fluid					2640						2640

TABLE 2-7

FUEL ANALYSIS SUMMARY - TEST SITE A - KEMMERER COAL

TEST NO.	16*	17	21	22	23	24	26A	26B	27	28	29	30	40	AVG
PROXIMATE (as rec.)														
% Moisture	17.85	17.80	17.83	18.94	20.43	19.56	18.09	20.42	17.17	18.29	19.79	20.34	17.83	18.64
% Ash	6.97	3.94	2.65	2.63	2.86	2.92	3.27	3.14	3.54	3.02	2.80	2.81	4.58	3.46
% Volatile	33.20	35.72	35.99	34.45	34.61	34.67	35.31	33.92	35.04	34.78	34.75	34.63	34.05	34.70
% Fixed Carbon	42.16	42.54	43.53	43.98	42.10	42.85	43.33	42.52	44.25	43.91	42.66	42.22	43.54	43.05
BTU/lb	9969	10350	10514	10338	10242	10323	10487	10158	10393	10475	10372	10202	10206	10310
% Sulfur	0.62	0.63	0.49	0.54	0.56	0.58	0.75	0.77	0.85	0.65	0.59	0.53	0.63	0.63
ULTIMATE (as rec.)														
% Moisture					20.43				17.17		19.79		17.83	
% Carbon					58.97				60.44		60.30		58.99	
% Hydrogen					4.02				4.12		4.09		4.08	
% Nitrogen					0.72				1.01		0.83		0.84	
% Chlorine					0.00				0.01		0.02		0.00	
% Sulfur					0.56				0.85		0.59		0.63	
% Ash					2.86				3.54		2.80		4.58	
% Oxygen (diff)					12.44				12.86		11.58		13.05	
ASH FUSION (reducing)														
Initial Deformation						2260					2180			2220
Soft. (H=W)						2360					2240			2300
Soft. (H=1/2W)						2460					2325			2393
Fluid						2565					2410			2488

* Not included in averages

TABLE 2-8

FUEL ANALYSIS SUMMARY - TEST SITE A - CONSOLIDATION COAL

TEST NO.	34	35	36	37	38	39	AVG.
PROXIMATE (as rec.)							
% Moisture	12.72	13.06	12.72	11.29	12.87	14.28	12.82
% Ash	8.79	7.81	6.14	8.23	8.71	7.68	7.89
% Volatile	33.82	34.37	34.60	34.34	33.96	33.79	34.15
% Fixed Carbon	44.67	44.76	46.5[illegible]	46.14	44.46	44.25	45.14
BTU/lb	10534	10683	10920	10768	10479	10386	10628
% Sulfur	0,73	0.35	0.31	0.28	0.32	0.40	0.40
ULTIMATE (as rec.)							
% Moisture		13.06					
% Carbon		62.19					
% Hydrogen		4.11					
% Nitrogen		0.82					
% Chlorine		0.01					
% Sulfur		0.35					
% Ash		7.81					
% Oxygen (diff.)		11.65					
ASH FUSION (reducing)							
Initial Deformation		2170					2170
Soft. (H=W)		2265					2265
Soft. (H=1/2W)		2355					2355
Fluid		2420					2420

TABLE 2-9

MINERAL ANALYSIS OF ASH
TEST SITE A

Coal Test No.	Stansbury 10	Kemmerer 40	Consolidation 35
MINERAL ANALYSIS OF ASH			
Silica, SiO_2	59.32	51.88	46.02
Alumina, Al_2O_3	12.90	18.49	18.65
Titania, TiO_2	0.55	0.75	0.70
Ferric Oxide, Fe_2O_3	11.10	5.02	6.96
Lime, CaO	5.90	8.12	14.80
Magnesia, MgO	2.16	2.76	1.62
Potassium Oxide, K_2O	1.06	0.90	0.65
Sodium Oxide, Na_2O	0.32	0.32	1.02
Sulfur Trioxide, SO_3	5.71	10.77	8.23
Phos. Pentoxide, P_2O_5	0.19	0.18	0.78
Undetermined	0.77	0.81	0.57
Silica Value	75.57	76.54	66.31
Base: Acid ratio	0.28	0.24	0.38
T_{250} Temperature	2590°F	2665°F	2435°F

TABLE 2-10

SUMMARY OF STEAM FLOWS AND HEAT RELEASE RATES
TEST SITE A

Test No.	Capacity %	Steam Flow 10^3 lb/hr	Heat Input 10^6BTU/hr	Front Foot Heat Release 10^4BTU/ft/hr	Grate Heat Release 10^3BTU/ft^2/hr	Furnace Heat Release 10^2BTU/ft^3/hr
1	64	191	228	839	441	136
2	59	177	211	776	408	126
3	61	182	217	801	421	130
4	60	180	208	768	404	125
5	72	217	255	939	494	153
6	70	210	223	822	433	134
7	68	203	240	886	466	144
8	65	196	236	871	458	142
9	61	182	210	774	407	126
10	37	110	127	470	247	76
11	41	124	144	532	280	87
12	45	136	159	587	309	95
13	77	232	272	1001	527	163
14	72	217	261	962	506	156
15	73	220	262	965	508	157
16	59	178	210	776	408	126
17	52	156	181	668	352	109
18	46	139	161	595	313	97
19	44	132	155	570	300	93
20	42	127	155	570	300	93
21	82	246	295	1088	572	177
22	83	250	300	1106	582	180
23	59	176	210	774	408	126
24	59	176	210	774	407	126
25	74	222	267	984	518	160
26A	70	211	255	938	494	153
26B	74	221	268	983	517	160
27	81	243	294	1086	571	177
28	84	251	304	1122	591	182
29	85	255	310	1143	601	186
30	80	239	290	1068	562	174
31	53	159	192	708	373	115
32	83	248	301	1111	585	181
33	79	237	289	1066	561	173
34	76	289	277	1022	538	166
35	76	227	271	1000	526	163
36	80	240	289	1066	561	173
37	87	259	316	1166	614	190
38	59	176	212	782	412	127
39	60	180	219	808	425	131
40	66	198	240	886	466	144

3.0 DESCRIPTION OF FACILITY TESTED AND COALS FIRED

This Section discusses the general physical layout and operational characteristics of Boiler A. The coals utilized in this test series are also discussed.

3.1 Boiler A Description

Figure 3-1 shows a sectional side elevation of the boiler unit used during the tests. The boiler is a Foster Wheeler unit. It is designed to produce 300,000 pounds per hour of steam at 320 psi. The steam is not superheated and thus leaves the boiler at its saturation temperature of 427°F. The boiler was built and first operated in 1976.

The stoker is a Detroit Stoker unit. It has seven feeders and a split traveling grate with front ash discharge. Overfire air is introduced through two rows of jets on the back wall and two rows of jets on the front wall. Each row of jets is dampered manually. The overfire air system is completely separate from the forced draft system and is not heated by the air heater.

The arrangement of the boiler's economizer, air heater and collection equipment is shown in Figure 3-2. This figure shows a block diagram of how the individual components are arranged. The gas flows from the boiler through a tubular type air preheater (with a settling chamber), into a multiclone dust collector, into an electrostatic precipitator, then through the economizer followed by an induced draft fan, and finally through a scrubber for sulfur oxide removal. From there it exits up the stack.

Flyash is reinjected continuously from the boiler hopper and the air heater hopper. Flyash from the mechanical collector hopper can be either reinjected or dumped into a surge hopper and discarded. Flyash reinjection air comes from the overfire air system.

Sample ports were installed at the locations shown on the boiler schematic, Figure 3-2. These sample locations were not ideal relative to EPA testing recommendations or for performing boiler heat balances. Because

Reproduced from
best available copy.

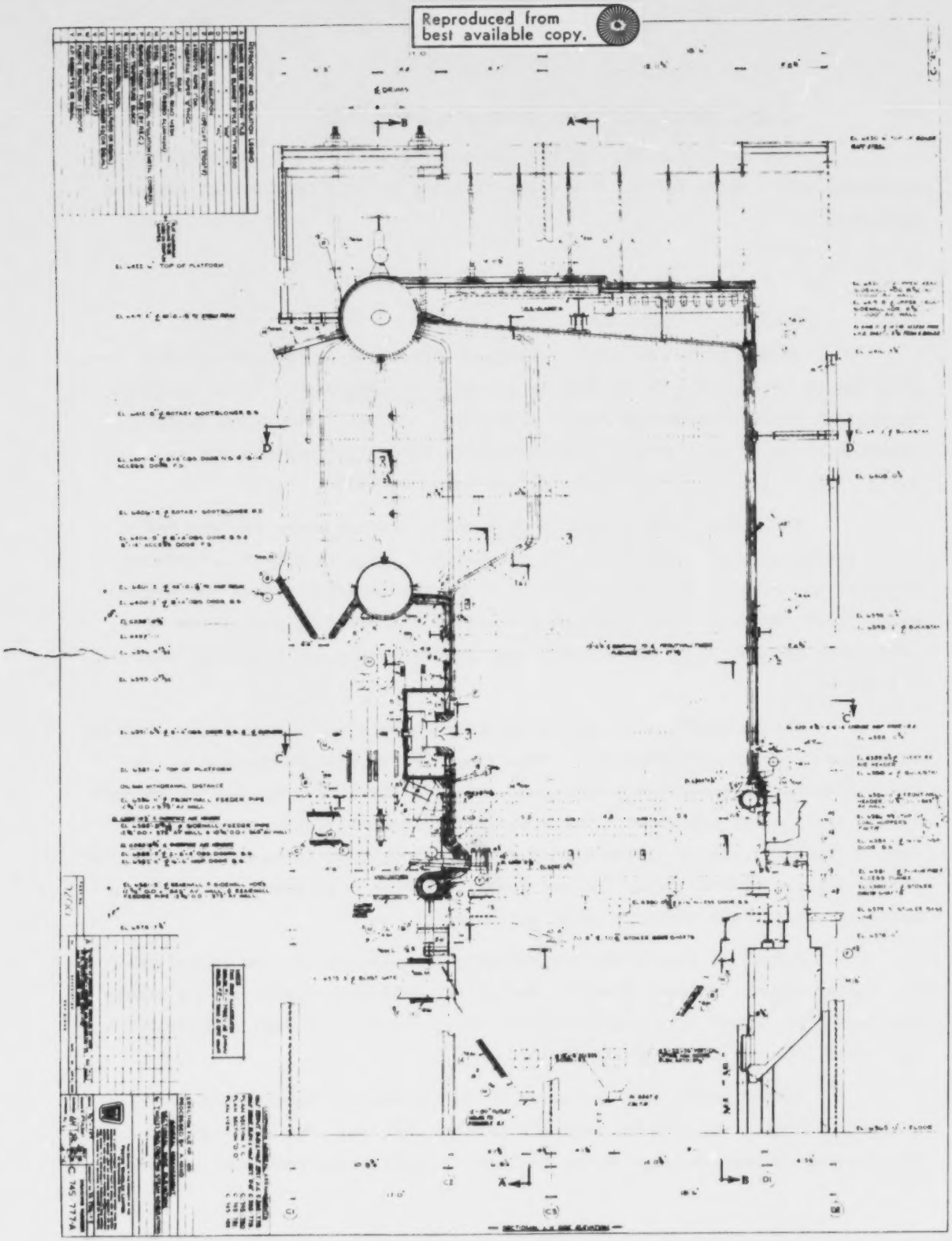


FIGURE 3-1. BOILER A SECTIONAL SIDE ELEVATION

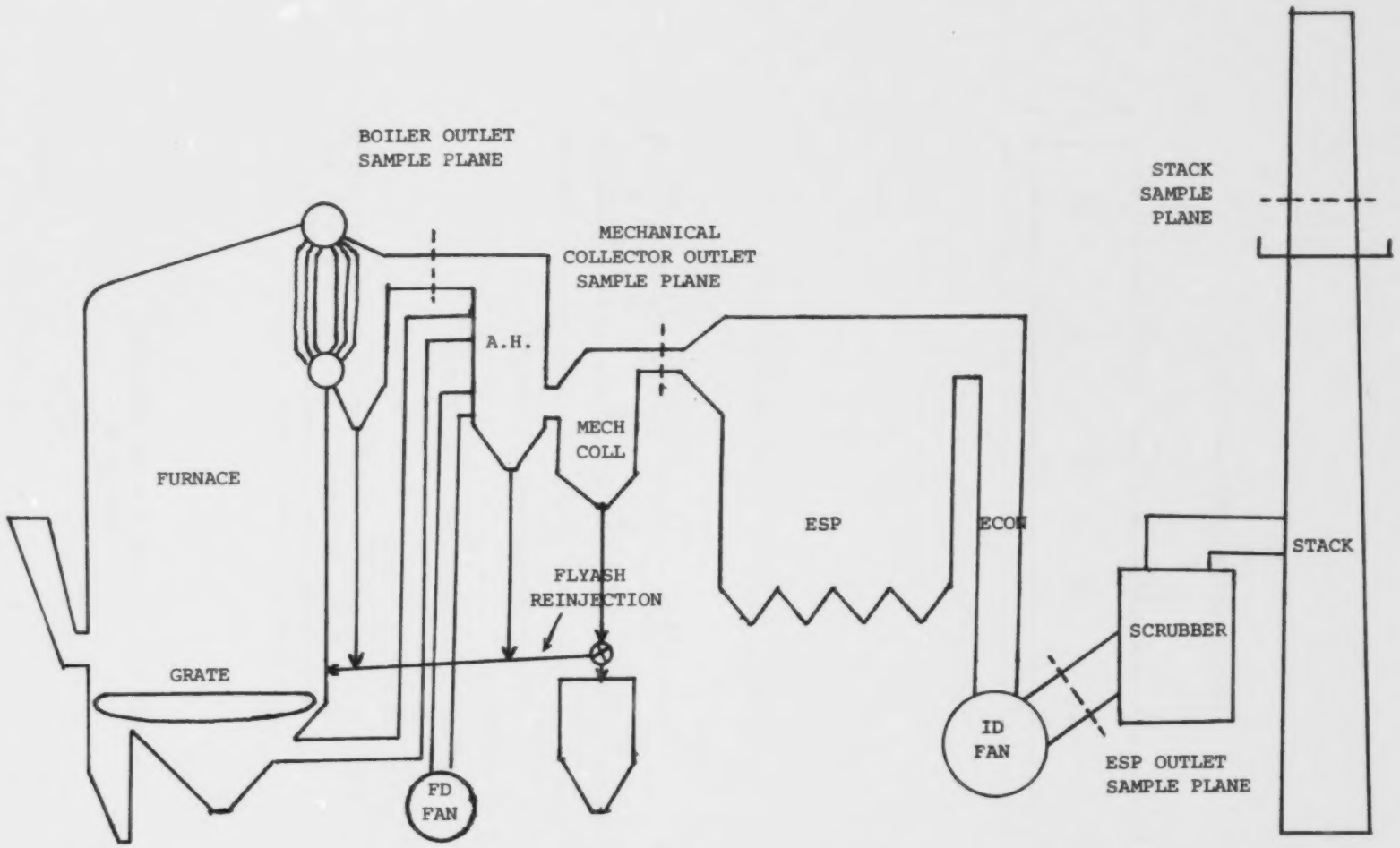
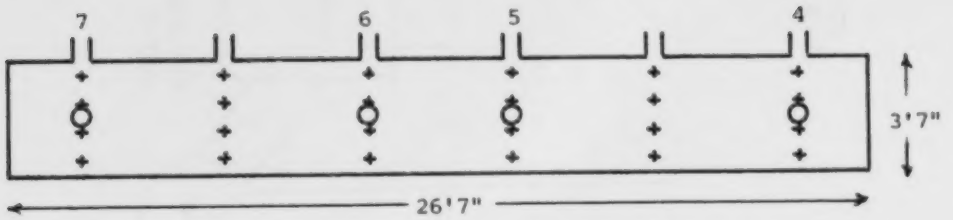


FIGURE 3-2. BOILER A SCHEMATIC
(Not Drawn to Scale)

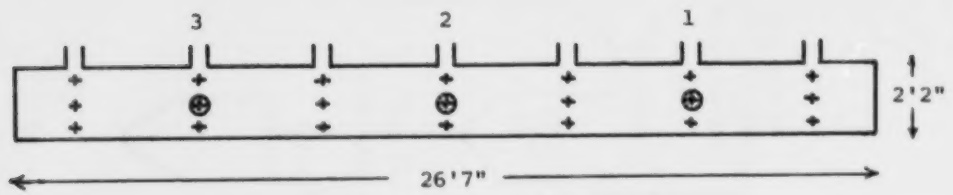
KVB 15900-521

BOILER OUTLET SAMPLING PLANE



Cross Sectional Area = 95.26 ft^2

MECHANICAL COLLECTOR OUTLET SAMPLING PLANE



Cross Sectional Area = 57.04 ft^2

KEY: + Particulate Sampling Point
O Gaseous Sampling Point

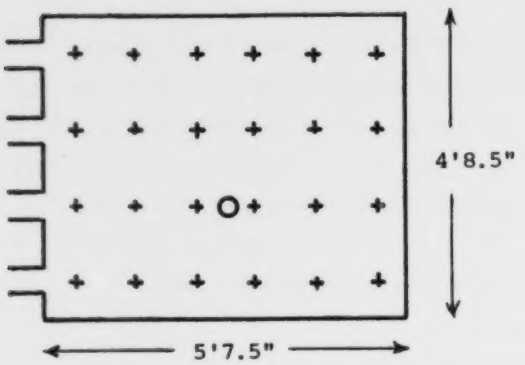
SCALE: 1 inch = 5 feet

NOTE: Numbers refer to probe numbers on original gaseous data sheets for Tests 21-40. For Tests 1-20 all seven probes were in mechanical outlet duct numbered 1-7 right to left.

FIGURE 3-3. SAMPLE PLANE GEOMETRY
TEST SITE A

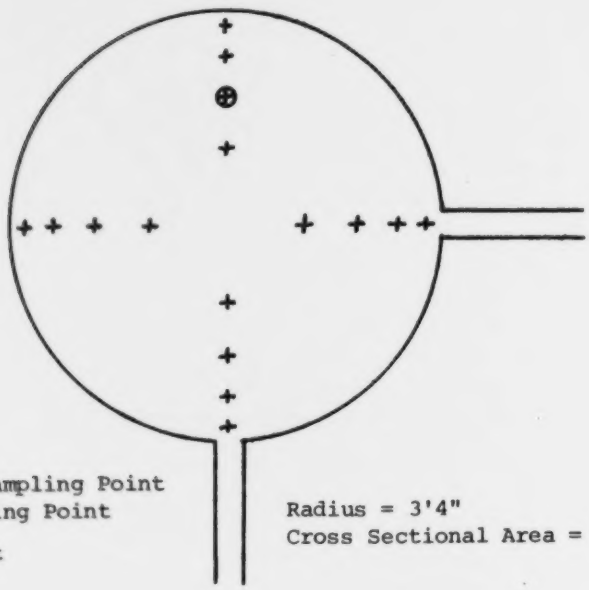
15900-521

PRECIPITATOR OUTLET SAMPLING PLANE



Cross Sectional Area = 26.48 ft^2

STACK SAMPLING PLANE



KEY: + Particulate Sampling Point
O Gaseous Sampling Point

SCALE: 1 inch = 2.5 feet

Radius = 3'4"
Cross Sectional Area = 34.91 ft^2

FIGURE 3-4. SAMPLE PLANE GEOMETRY
TEST SITE A

of physical limitations on the installation of sample ports, heat loss calculations required assumptions to be made concerning the collection efficiency of the dust collector which could not be isolated by a separate sampling station from the air heater. Sample plane geometry is shown in Figures 3-3 and 3-4.

The facility has two identical boilers. When both are on line, the one being tested can be put on manual operation and process demand fluctuations can be met by modulation of the second boiler. Unfortunately, the other boiler was down during much of the test program so that getting and maintaining the desired loads was a problem. The test boiler had to meet process demands. This problem was aggravated by the fact that furnace excess air was always on manual control because of automatic control problems with the FD fan dampers.

The boiler design data is summarized in Table 3-1 following. The design performance and pressure drops are given in Table 3-2. This data was estimated utilizing a design coal whose properties are given in Table 3-3.

TABLE 3-1

BOILER A DESIGN DATA

Foster Wheeler Boiler

Design Steaming Capacity	300,000 lb/hr
Design Pressure	350 psi
Final Steam Temperature	427°F
Boiler Heating Surface	20,186 ft^2
Waterwall Heating Surface	2,982 ft^2
Economizer Heating Surface	13,276 ft^2
Furnace Volume	16,712 ft^3
Year Built	1976
Type	VOSP

Detroit Stoker

Number of feeders	7
Grate Type	Split, Continuous Front Discharge
Grate Length (shaft to shaft)	20'8"
Grate Width	27'1-1/2"
Effective Grate Area	515.4 ft^2
Recommended Coal Sizing	3/4"x0 with no more than 25% thru 1/4"
Grate Thermocouple Location	6 in air seal beams, 23-1/8" forward of rear grate shaft

Overfire Air

Upper Rear:	25 jets @ 12" spacing, 6'0" above grate, 9° below horizontal
Lower Rear:	27 jets @ 8-16" spacing, 2'2" above grate except end two which are 1'0" above grate, horizontal
Upper Front:	25 jets @ 12" spacing, 6'6" above grate, 19° below horizontal
Lower Front:	Underfeeder air located about 10" above grate
Discussion:	The OFA system is completely separate from the FD system. The overfire air is nonheated ambient air from inside the plant. Maximum obtainable OFA pressures are 12-15 in. H_2O.

Flyash Reinjection

Boiler Hopper:	6 injectors @ 4'0" and 4'4" spacings
Air Heater Hopper:	7 injectors @ 4'0" and 4'4" spacings
Mechanical Hopper:	12 injectors @ 2'0" and 2'4" spacings
Discussion:	Mechanical hopper ash can be stored in a surge hopper and discarded rather than reinjected at the boiler operators option.

TABLE 3-2

BOILER A DESIGN PERFORMANCE SUMMARY

	Max. Load	Base Load
Steam Flow, 10^3lb/hr	300	250
Steam Temperature Boiler Outlet, °F	427	427
Pressure Boiler Drum, psig	320	320
Temp. Feedwater Entering Unit, °F	240	240
Temp. Feedwater Leaving Economizer, °F	313	291
Temp. Air Entering Unit, °F	80	80
Temp. Air Leaving Air Heater, °F	317	346
Temp. Gas Leaving Furnace, °F	1,960	--
Temp. Gas Leaving Boiler, °F	765	687
Temp. Gas Leaving Air Heater, °F	600	498
Temp. Gas Leaving Economizer, °F	350	310
Excess Air Leaving Furnace, %	25	25
Wet Gas Entering Air Heater, 10^3lb/hr	364	302
Wet Gas Leaving Air Heater, 10^3lb/hr	364	302
Air Entering Air Heater, 10^3lb/hr	326	271
Air Leaving Air Heater, 10^3lb/hr	326	271
Draft in Furnace, in. H_2O	-.2	-.2
Gas Side Loss Thru Boiler, in. H_2O	0.56	0.39
Gas Side Loss Thru Mechanical D.C., in. H_2O	2.50	1.72
Gas Side Loss Thru Air Heater, in. H_2O	2.90	2.00
Gas Side Loss Thru ESP, in. H_2O	0.64	0.44
Gas Side Loss Thru Economizer, in. H_2O	2.07	1.42
Gas Side Loss Thru Flues, in. H_2O	0.64	0.44
Air Side Loss Thru Air Heater, in. H_2O	2.74	1.89
Air Side Loss Thru Ducts, in. H_2O	0.76	0.53
Air Side Loss Thru Grate, in. H_2O	3.17	2.19
Air Side Loss Thru Steam Coil, in. H_2O	1.00	0.69
Air Side Loss Thru Air Measuring Device, in. H_2O	1.27	0.88
Fuel Flow, 10^3/lb/hr	31,726	26,000
Liberation, BTU/hr/ft^3 total vol.	21,452	17,584
Dry Gas Loss, %	6.47	5.51
Hydrogen & Moisture in Fuel Loss, %	5.50	5.41
Moisture in Air Loss, %	0.11	0.09
Unburned Combustible Loss, %	1.70	1.41
Radiation Loss From Boiler, %	0.34	0.41
Radiation Loss From Precipitator, %	0.70	0.70
Manufacturers Margin, %	1.50	1.50
Unit Efficiency, %	83.68	84.97

TABLE 3-3

ULTIMATE ANALYSIS OF COAL UPON WHICH PERFORMANCE DATA IS BASED

Ash	2.67% (8% max.)
S	0.81% (1.5% max.)
H_2	4.71%
C	64.83%
N_2	1.08%
O_2	14.90%
H_2O	11.00%
BTU/lb as Fired	11,300

3.2 Coals Utilized

During the test program on Boiler A three coals were utilized. These were a Wyoming coal from Stansbury Coal Company, a Wyoming coal from Kemmerer Coal Company, and a Colorado coal from Consolidation Coal Company. Each of these coals has different thermal and ash properties. Table 3-4 below summarizes the average as fired proximate analysis of the coals tested in Boiler A. A complete fuel analysis summary for each coal is given in Tables 2-6 thru 2-9 in the Executive Summary, Section 2.0.

TABLE 3-4

AS FIRED PROXIMATE ANALYSIS OF COALS TESTED IN BOILER A

Coal Company:	Stansbury	Kemmerer	Consolidation
% Moisture	14.31	18.64	12.82
% Ash	6.09	3.46	7.89
% Volatile	34.71	34.70	34.15
% Fixed Carbon	44.90	43.05	45.14
BTU/lb	10547	10310	10628
% Sulfur	0.93	0.63	0.40
Initial Deformation of Ash (Reducing)	2000°F	2220°F	2170°F

The Kemmerer coal differed from the others by its higher moisture (19%) and lower ash (3.5%). By comparison, the Consolidation coal averaged 13% moisture and 8% ash. The Stansbury coal differed primarily in its higher sulfur content. All three coals had low ash fusion temperatures.

The coal handling system at Test Site A operates as follows. Bottom dump hopper cars discharge the coal onto a system of three belt conveyors which deliver the coal to a standpipe. The standpipe is a ported cylinder which builds a conical coal pile and minimizes wind-related losses during stacking operations.

A front end loader transfers the coal from the active pile or from dead storage to a reclaim hopper and an apron feeder. The coal is conveyed from the apron feeder to a tripper which fills the bunker above the boiler.

The dates of introduction for each of the three coals are given in Table 3-5 below. Also shown are the test numbers corresponding to each of these coals.

TABLE 3-5

TEST NUMBERS CORRESPONDING TO COALS FIRED

Test No.	Coal Source	Date Introduced
1-15	Stansbury	August 3, 1977
16-17	Kemmerer I	August 28, 1977
18-19	Stansbury	September 9, 1977
20-33	Kemmerer II	September 12, 1977
34-39	Consolidation	October 25, 1977
40	Kemmerer II	November 3, 1977

The Kemmerer coal burned during tests 16 and 17 reportedly came from a different seam than the coal burned during tests 20-33. During both tests 16 and 17 a high ash, low BTU coal was blended into the Kemmerer coal. This blending was especially evident in test 16's coal analysis as shown in Table 2-7.

4.0 TEST EQUIPMENT AND PROCEDURES

This Section details how specific emissions were measured and the sampling procedures followed to assure that accurate, reliable data was collected.

4.1 Gaseous Emissions Measurements (NO, NO_2, CO, CO_2, O_2, HC).

A description is given below of the analytical instrumentation and related equipment, and the gas sampling and conditioning system, all of which are located in a mobile testing van owned and operated by KVB. The systems have been developed as a result of over five years of testing, and are operational and fully checked out.

A. Analytical Instruments and Related Equipment. The analytical system consists of five instruments and associated equipment for simultaneously measuring the composition of the flue gas. The analyzers, recorders, valves, controls, and manifolding are mounted to a panel in the vehicle. The analyzers are shock mounted to prevent vibration damage. The flue gas constituents which are measured are oxides of nitrogen (NO, NOx), carbon monoxide (CO), carbon dioxide (CO_2), oxygen (O_2), and gaseous hydrocarbons (HC).

Listed below are the measurement parameters, the analyzer model furnished, and the range and accuracy of each parameter for the system. A detailed discussion of each analyzer follows:

- Nitric Oxide/total oxides of nitrogen (NO/NOx)

Thermo Electron Model 10 Chemiluminescent Analyzer
Range: 0-2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm NO
Accuracy: ±1% of full scale

- Carbon Monoxide

Beckman Model 315B NDIR Analyzer
Range: 0-500 and 0-2000 ppm CO
Accuracy: ±1% of full scale

- Carbon Dioxide

Beckman Model 864 NDIR Analyzer

Range: 0-5% and 0-20% CO_2

Accuracy: ±1% of full scale

- Oxygen

Teledyne Model 326A Fuel Cell Analyzer

Range: 0-5, 10 and 25% O_2 full scale

Accuracy: ±1% of full scale

- Hydrocarbons

Beckman Model 402 Flame Ionization Analyzer

Range: 5 ppm full scale to 10% full scale

Accuracy: ±1% of full scale

The oxides of nitrogen monitoring instrument used is a Thermo Electron chemiluminescent nitric oxide analyzer. The operational basis of the instrument is the chemiluminescent reaction of NO and O_3 to form NO_2. Light emission results when electronically excited NO_2 molecules revert to their ground state. This resulting chemiluminescence is monitored through an optical filter by a high sensitivity photomultiplier, the output of which is linearly proportional to the NO concentration.

Air for the ozonator is drawn from ambient through an air dryer and a 10 micron filter element. Flow control for the instrument is accomplished by means of a small bellows pump mounted on the vent of the instrument downstream of a separator which insures that no water collects in the pump.

The basic analyzer is sensitive only to NO molecules. To measure NOx (i.e., $NO+NO_2$), the NO_2 is first converted to NO. This is accomplished by a converter which is included with the analyzer. The conversion occurs as the gas passes through a thermally insulated, resistance heated, stainless steel coil. With the application of heat, NO_2 molecules in the sample gas are reduced to NO molecules, and the analyzer now reads NOx. NO_2 is obtained by the difference in readings obtained with and without the converter in operation.

Specifications: Accuracy 1% of full scale

Span Stability ±1% of full scale in 24 hours

Zero Stability ±1 ppm in 24 hours

Power Requirements 115±10V, 60 Hz, 1000 watts

Response 90% of full scale in 1 sec. (NOx mode), 0.7 sec NO mode

Output 4-20 ma

Sensitivity 0.5 ppm

Linearity ±1% of full scale

Vacuum detector operation

Range: 2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm full scale

Carbon Monoxide concentration is measured by a Beckman 315B non-dispersive infrared analyzer. This instrument measures the differential in infrared energy absorbed from energy beams passed through a reference cell (containing a gas selected to have minimal absorption of infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale from 0 to 100 and is then related to the concentration of the specie of interest by calibration curves supplied with the instrument. The operating ranges for the CO analyzer are 0-500 and 0-2000 ppm.

Specifications: Span Stability ±1% of full scale in 24 hours

Zero Stability ±1% of full scale in 24 hours

Ambient Temperature Range 32°F to 120°F

Line Voltage 115 ± 15 V rms

Response: 90% of full scale in 0.5 or 2.5 sec.

Precision: ±1% of full scale

Output: 4-20 ma

Carbon Dioxide concentration is measured by a Beckman Model 864 short path-length, non-dispersive infrared analyzer. This instrument measures the differential in infrared energy absorbed from energy beams passed through a reference cell (containing a gas selected to have minimal absorption of

infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale from 0 to 100 and is then related to the concentration of the specie of interest by calibration curves supplied with the instrument. The operating ranges for the CO_2 analyzer are 0-5% and 0-20%.

Specifications: Span Stability ±1% of full scale in 24 hours
Zero Stability ±1% of full scale in 24 hours
Ambient Temperature Range 32°F to 120°F
Line Voltage 115 ± 15 V rms
Response: 90% of full scale in 0.5 or 2.5 sec.
Precision: ±1% of full scale
Output: 4-20 ma

The Oxygen content of the flue gas sample is automatically and continuously determined with a Teledyne Model 326A Oxygen analyzer. Oxygen in the flue gas diffuses through a Teflon membrane and is reduced on the surface of the cathode. A corresponding oxidation occurs at the anode internally and an electric current is produced that is proportional to the concentration of oxygen. This current is measured and conditioned by the instrument's electronic circuitry to give a final output in percent O_2 by volume for operating ranges of 0% to 5%, 0% to 10%, or 0% to 25%.

Specifications: Precision: ±1% of full scale
Response: 90% in less than 40 sec.
Sensitivity: 1% of low range
Linearity: ±1% of full scale
Ambient Temperature Range: 32-125°F
Fuel cell life expectancy: 40,000%-hrs.
Power Requirement: 115 VAC, 50-60 Hz, 100 watts
Output: 4-20 ma

Hydrocarbons are measured using a Beckman Model 402 hydrocarbon analyzer which utilizes the flame ionization method of detection. The sample is drawn through a heated line to prevent the loss of higher molecular weight

hydrocarbons to the analyzer. It is then filtered and supplied to the burner by means of a pump and flow control system. The sensor, which is the burner, has its flame sustained by regulated flows of fuel (40% hydrogen + 60% helium) and air. In the flame, the hydrocarbon components of the sample undergo a complete ionization that produces electrons and positive ions. Polarized electrodes collect these ions, causing a small current to flow through an electronic measuring circuit. This ionization current is proportional to the concentration of hydrocarbon atoms which enter the burner. The instrument is available with range selection from 5 ppm to 10% full scale as CH_4.

Specifications: Full scale sensitivity, adjustable from 5 ppm CH_4 to 10% CH_4

Ranges: Range multiplier switch has 8 positions: X1, X5, X10, X50, X100, X500, X1000, and X5000. In addition, span control provides continuously variable adjustment within a dynamic range of 10:1

Response Time: 90% full scale in 0.5 sec.

Precision: ±1% of full scale

Electronic Stability: ±1% of full scale for successive identical samples

Reproducibility: ±1% of full scale for successive identical samples

Analysis Temperature: Ambient

Ambient Temperature: 32°F to 110°F

Output: 4-20 ma

Air Requirements: 350 to 400 cc/min of clean, hydrocarbon-free air, supplied at 30 to 200 psig

Fuel Gas Requirements: 75 to 80 cc/min of pre-mixed fuel consisting of 40% hydrogen and 60% nitrogen or helium, supplied at 30 to 200 psig

Electrical Power Requirements: 120v, 60 Hz

Automatic Flame-out indication and fuel shut-off valve

Recording Instruments. The outputs of the four analyzers are presented on front panel meters and are simultaneously recorded on a Texas Instrument Model FLO4W6D four pen strip chart recorder. The recorder specifications are as follows:

Specifications: Strip Chart display
Chart Size: 9-3/4 inch
Accuracy: ±0.25%
Linearity: <0.1%
Line Voltage: 120V ± 10% at 60 Hz
Span Step Response: 1 sec.

B. Gas Sampling and Conditioning System. The gas sampling and conditioning system consists of the probes, sample line, valves, pumps, filters and other components necessary to deliver a representative, conditioned sample gas to the analytical instrumentation. The following section describes the system and the components which make up the system. The entire gas sampling and conditioning system shown schematically in Figure 3-1 is contained in the emission test vehicle.

4.2 Gaseous Emission Sampling Techniques, (NOx, CO, CO_2, O_2, HC)

Boiler access points for gaseous sampling are selected in the same sample plane as are particulate sample points. Each probe consists of one-half inch 316 stainless steel heavy wall tubing. A 100 micron Mott Metallurgical Corp. sintered stainless steel filter is attached to each probe for removal of particulate material.

Gas samples to be analyzed for O_2, CO_2, CO and NO are conveyed to the KVB mobile laboratory through 3/8 inch nylon sample lines. After passing through bubblers for flow control, the samples pass through a diaphragm pump and a refrigerated dryer to reduce the sample dew point temperature to 35°F. After the dryer, the sample gas is split between the various continuous gas monitors for analysis. Flow through each continuous monitor is accurately controlled with rotometers. Excess flow is vented to the outside. Gas samples are drawn sequentially from all probes for each test. The average emission values are reported in this report.

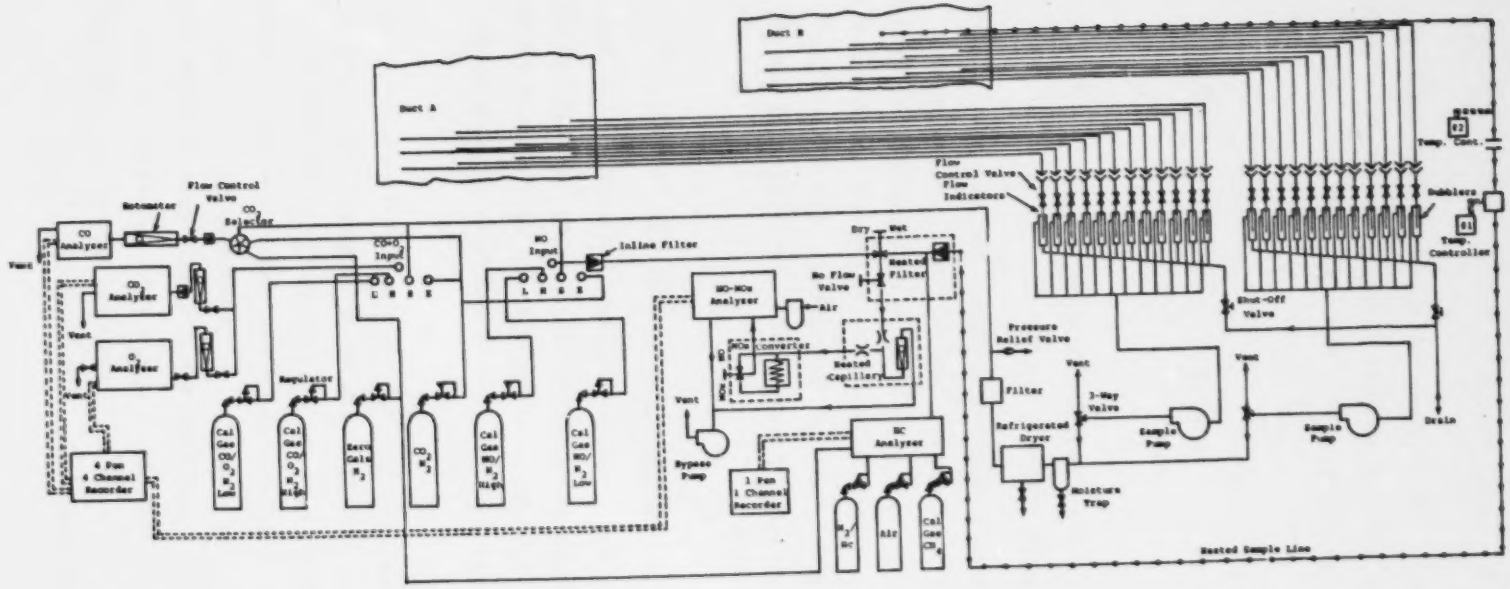


FIGURE 4-1. FLOW SCHEMATIC OF MOBILE FLUE GAS MONITORING LABORATORY

KVB 15900-521

4.3 Sulfur Oxides (SOx) Measurement and Procedure

Measurement of SO_2 and SO_3 concentrations are made by wet chemical analysis using the "Shell-Emeryville" method. In this technique the gas sample is drawn from the stack through a glass probe (Figure 4-2), containing a quartz wool filter to remove particulate matter, into a system of three sintered glass plate absorbers (Figure 4-3). The first two absorbers contain aqueous isopropyl alcohol and remove the sulfur trioxide; the third contains aqueous hydrogen peroxide solution which absorbs the sulfur dioxide. Some of the sulfur trioxide is removed by the first absorber, while the remainder, which passes through as a sulfuric acid mist, is completely removed by the secondary absorber mounted above the first. After the gas sample has passed through the absorbers, the gas train is purged with nitrogen to transfer sulfur dioxide, which has dissolved in the first two absorbers, to the third absorber to complete the separation of the two components. The isopropyl alcohol is used to inhibit the oxidation of sulfur dioxide to sulfur trioxide before it gets to the third absorber.

The isopropyl alcohol absorber solutions are combined and the sulfate resulting from the sulfur trioxide absorption is titrated with standard lead perchlorate solution using Sulfonazo III indicator. In a similar manner, the hydrogen peroxide solution is titrated for the sulfate resulting from the sulfur dioxide absorption.

The gas sample is drawn from the flue by a single probe made of quartz glass inserted into the duct approximately one-third to one-half way. The inlet end of the probe holds a quartz wool filter to remove particulate matter. It is important that the entire probe temperature be kept above the dew point of sulfuric acid during sampling (minimum temperature of 260°C). This is accomplished by wrapping the probe with a heating tape.

Three repetitions of SOx sampling are made at each test point.

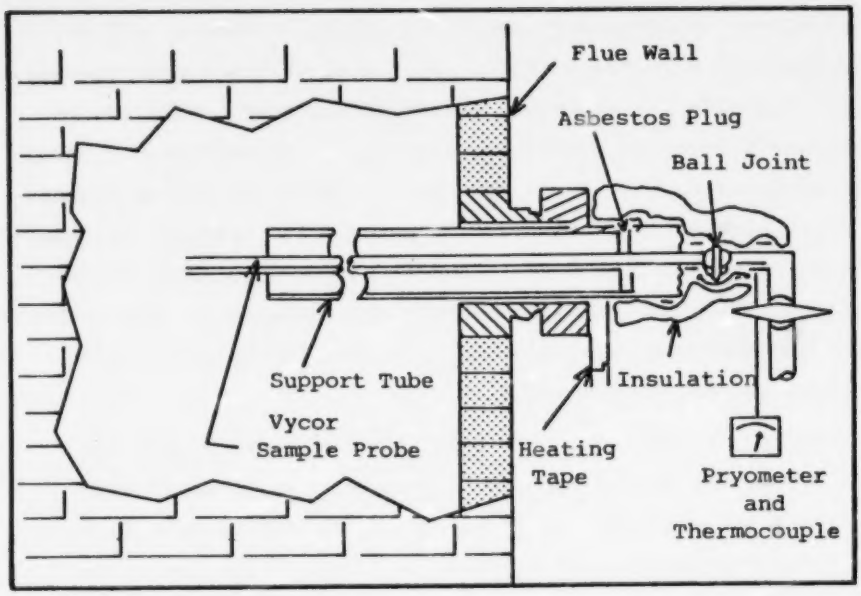


FIGURE 4-2. SOx SAMPLE PROBE CONSTRUCTION

15900-521

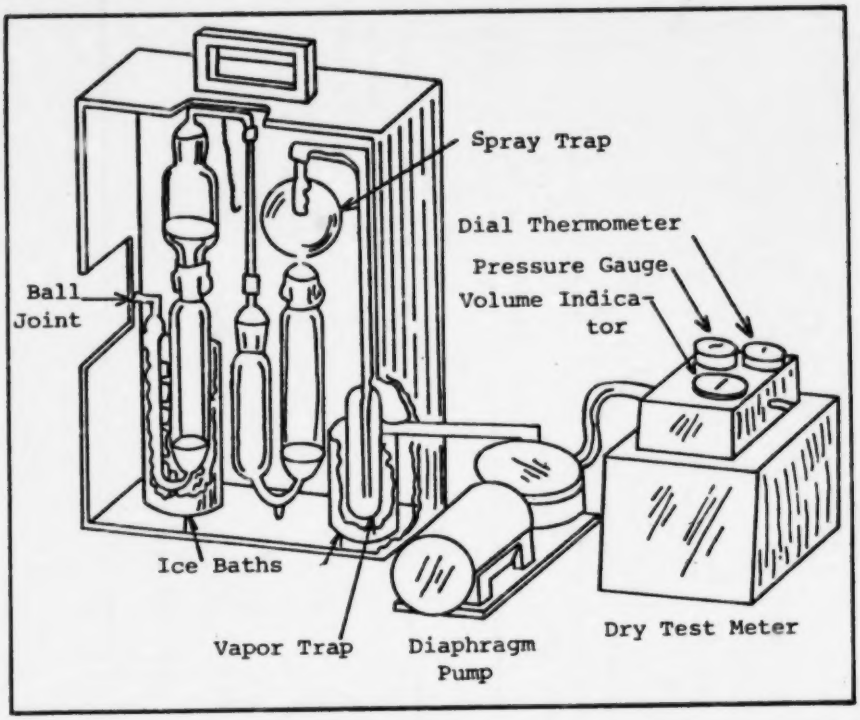


FIGURE 4-3. SULFUR OXIDES SAMPLING TRAIN

15900-521

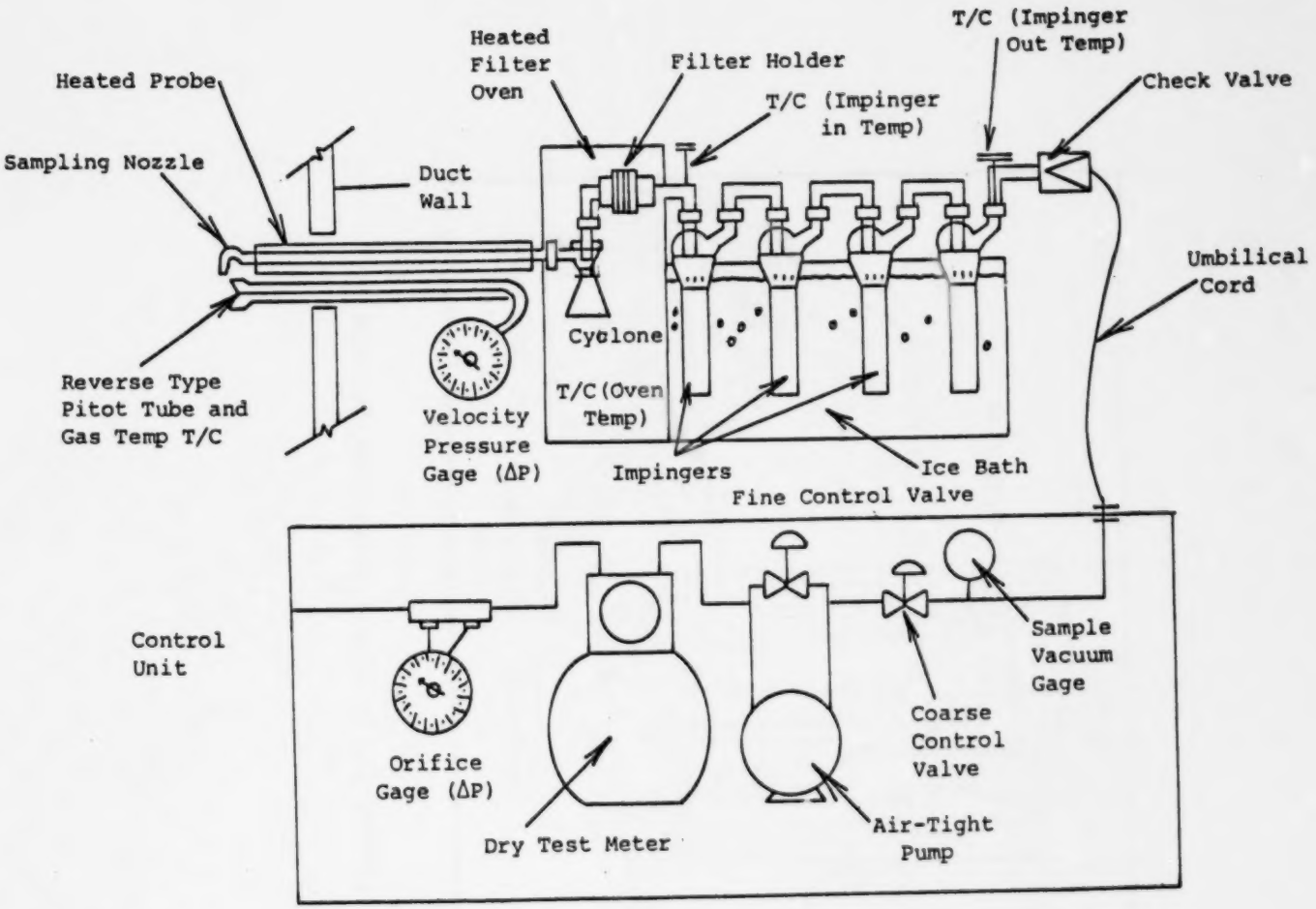


FIGURE 4-4. PARTICULATE SAMPLING TRAIN

15900-521

4.4 Particulates Measurement and Procedures

Particulate samples are taken at the same sample ports as the gaseous emission samples using a Joy Manufacturing Company portable effluent sampler (Figure 4-4). This system, which meets the EPA design specifications for Test Method 5, Determination of Particulate Emissions from Stationary Sources (Federal Register, Volume 36, No. 27, page 24888, December 23, 1971), is used to perform both the initial velocity traverse and the particulate sample collection. Dry particulates are collected in a heated case using first a cyclone to separate particles larger than 5 microns and a 100 mm glass fiber filter for retention of particles down to 0.3 microns. Condensible particulates are collected in a train of four Greenburg-Smith impingers in an ice water bath. The control unit includes a total gas meter and thermocouple indicator. A pitot tube system is provided for setting sample flows to obtain isokinetic sampling conditions.

All peripheral equipment is carried in the instrument van. This includes a scale (accurate to $\pm$0.1mg), hot plate, drying oven (212°F), high temperature oven, desiccator, and related glassware. A particulate analysis laboratory is set up in the vicinity of the boiler in a vibration-free area. Here filters are prepared, tare weighed and weighed again after particulate collection. Also, probe washes are evaporated and weighed in the lab.

4.5 Particle Size Distribution Measurement and Procedure

The measurement of particle size distribution of the flyash is performed using a Brink Model "B" Cascade impactor. The Brink impactor is a five stage, low sample rate, cascade impactor suitable for measurements in high mass loading situations. A schematic of the Brink sampling train is shown in Figure 4-5.

Samples are pulled isokinetically from a single sample point. The flow rate through the impactor is held constant during sampling to preserve the impaction cut points.

Gelman type A-E binderless glass fiber filter paper is used as the collection substrate. The main purpose of the glass mats is to reduce

re-entrainment due to particle bounce. The 5/8 inch diameter mats are cut from larger stock with a cork bore and inserted in the collection plates. The collection plates with mats installed are desiccated 24 hours before tare weighing. After sampling, all particles adhering to the impactor walls are brushed down onto the collection plate immediately below. The plates are again desiccated 24 hours before weighing.

The cyclone catch is brushed onto a tare weighed paper, desiccated and weighed. The final filter, cut from the same fiber glass stock as the collection plate substrates, is treated the same as the collection plates.

The sampling procedure is straight forward. First, the gas velocity at the sample point is determined using a calibrated S-type pitot tube. For this purpose a hand held particulate probe, inclined manometer, thermocouple and indicator are used.

Second, a nozzle size is selected which will maintain isokinetic flow rates within the recommended .02-.07 ft^3/min rate at stack conditions. Having selected a nozzle and determined the required flow rate for isokinetics, the operating pressure drop across the impactor is determined from a calibration curve. This pressure drop is corrected for temperature, pressure and molecular weight of the gas to be sampled.

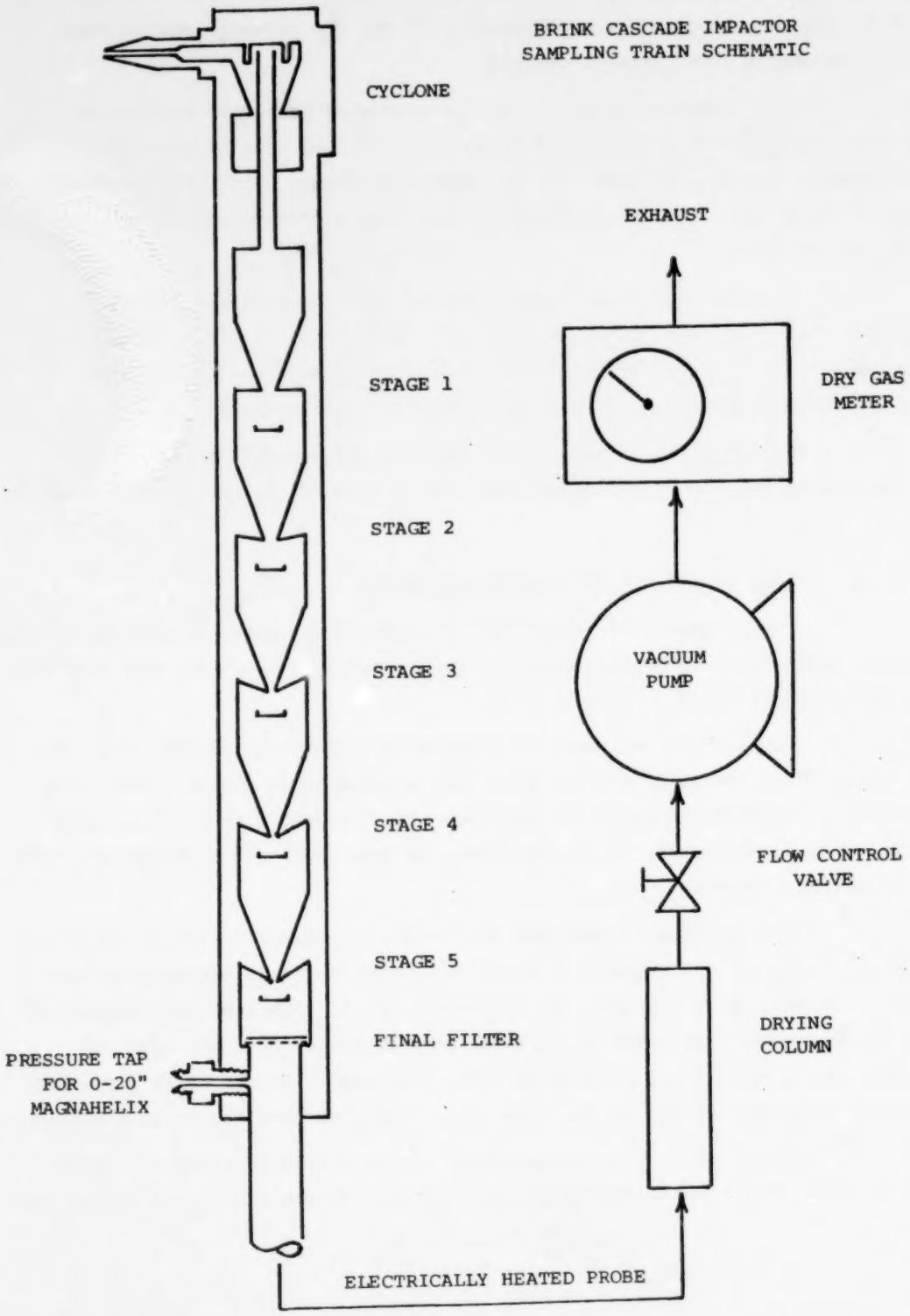
The impactor is placed in the duct for 20-30 minutes prior to sampling to allow it to be heated to stack temperature. During this warm up period, the sample nozzle is turned away from the direction of gas flow so that no particulates will be collected. Once hot, the stages are re-tightened with pipe wrenches to prevent leakage. The impactor's nozzle is then turned into the gas stream for collecting the particulate sample.

A sample is drawn at the predetermined ΔP for a time period which is dictated by mass loading and size distribution. To minimize weighing errors, it is desirable to collect several milligrams on each stage. However, to minimize re-entrainment, a rule of thumb is that no stage should be loaded above 10 mg.

The volume of dry gas sampled is measured with a dry gas meter. This allows calculation of actual isokinetics. The dry gas volume is also

FIGURE 4-5

BRINK CASCADE IMPACTOR
SAMPLING TRAIN SCHEMATIC



15900-521

used to convert test results to concentration units. Stack moisture used for calculating isokinetics is measured with the EPA Method 5 sample train during concurrent particulate sampling.

Data reduction involves a time-consuming iterative process and is best accomplished with the aid of a computer. For this purpose KVB developed a 223 step program for the Texas Instruments SR-52 card programmable calculator. With this program, Brink data reduction can be easily done in the field.

In addition to the Brink Cascade Impactor, particle sizing is accomplished by several other methods. The SASS train utilizes three sized cyclones and a final filter under controlled temperature and flow rates to achieve gravimetric separation at ten, three and one microns.

Selected flyash samples are sent to independent laboratories for sizing using the BAHCO centrifugal classifier (PTC 28) or the Coulter Counter.

4.6 Coal Sampling and Analysis Procedures

Coal samples are taken from the base of the non-segregating (conical) hopper immediately above the feeders. The reason for selecting this sampling location is discussed in Section 5.5.

Samples are collected by lifting the feeder inspection doors and allowing 10-20 pounds of coal to flow into a rectangular bucket. The first sample is discarded to purge the area near the inspection door. The second sample taken immediately after the first, is quartered with a sample splitter. One quarter is saved.

This process is repeated in a random pattern for each of the seven feeders. Samples are taken at fifteen to twenty minute intervals over the course of testing the boiler. At the completion of each test the cumulative sample is passed thru a sample splitter several times until the last two splits are approximately six pounds each. One sample is sealed in a plastic bag for chemical analysis. The other sample is processed for sieve analysis.

Sieve analysis is accomplished with a Gilson Porta-Screen Model PS-3. This device holds five trays with 14"x14" screen areas, and a dust pan.

Approximately six pounds of air-dried coal is placed in the top tray. After shaking for one minute, the sample in the top tray is removed and weighed. The second tray is shaken for two minutes, the third for four, the fourth for eight, the fifth for sixteen. In this way, wearing down of the particles is minimized while allowing sufficient time for size segregation. Screen sizes used are 1", 1/2", 1/4", #8 and #16 mesh.

Coal analysis is performed by Commercial Testing and Engineering Company, South Holland, Illinois. Each sample associated with a particulate loading or particle sizing test is given a proximate analysis. In addition, selected samples receive ultimate analysis ash fusion and mineral analysis of the ash.

4.7 Ash Collection and Analysis for Combustibles

Combustible content of flyash is determined in the field by KVB in accordance with ASTM D3173, "Moisture in the Analysis Sample of Coal and Coke" and ASTM D3174, "Ash in the Analysis Sample of Coal and Coke."

The flyash sample is collected by the EPA Method 5 particulate sample train while sampling for particulates. The cyclone catch is placed in a desiccated and tare weighed ceramic crucible. The crucible with sample is heated in an oven at 110°C to remove its moisture. It is then desiccated to room temperature and weighed. The crucible with sample is then placed in an electric muffle furnace maintained at a temperature of 750°C until ignition is complete and the sample has reached a constant weight. It is cooled in a desiccator over desiccant and weighed. Combustible content is calculated as the percent weight loss of the sample based on its post 110°C weight.

Bottom ash samples are collected from the bottom ash hopper within two hours after completion of each test. The ash hopper is cleared just prior to the test to insure that the hopper contains only ash generated during the test. Four five-pound samples are collected representing a cross-section of the ash hopper. These samples are mixed, quartered, and sent to Commercial Testing and Engineering Company, South Holland, Illinois, for combustible determination.

Multiclone ash samples are taken from four ports near the bottom of the hopper into which the multiclone ash is dumped prior to being discarded. This sample, approximately two liters, is sent to Commercial Testing and Engineering Company for combustible determination.

4.8 Boiler Efficiency Evaluation

Boiler efficiency is calculated using the ASME Test Form for Abbreviated Efficiency Test, Revised, September, 1965. The general approach to efficiency evaluation is based on the assessment of combustion losses. These losses can be grouped into three major categories: stack gas losses, combustible losses, and radiation losses. The first two groups of losses are measured directly. The third is estimated from the ABMA Standard Radiation Loss Chart.

Unlike the ASME test form where combustible losses are lumped into one category, combustible losses are calculated and reported separately for combustibles in the bottom ash, combustibles in the mechanically collected ash which is not reinjected, and combustibles in the flyash leaving the mechanical collector.

KVB has developed a program for the Texas Instrument's SR-52 card programmable calculator to compute the above heat losses. Use of this program helps minimize human error in the calculations.

4.9 Modified Smoke Spot Number

Modified Bacharach smoke spot numbers are determined using a Bacharach field service type smoke tester. ASTM procedures for this measurement apply only to oil fired units. Therefore, KVB has defined its own set of procedures which differ from ASTM D2156-65 procedure in the number of strokes taken with the hand pump. At this test site, one and two strokes were taken at the boiler outlet.

Smoke spot measurements are obtained by pulling a fixed volume of flue gas through a standard filter paper. The color (or shade) of the spot that is produced is matched visually with a standard smoke spot scale. The result is a "Smoke Number" which is used to characterize the density of smoke in the flue gas.

The sampling device is a hand pump similar to the one shown in Figure 4-6. It is a commercially available item that with ten strokes can pass 36,900 ±1650 cubic centimeters of gas at 16°C and 1 atmosphere pressure through an enclosed filter paper for each 6.5 square centimeters effective surface area of the filter paper.

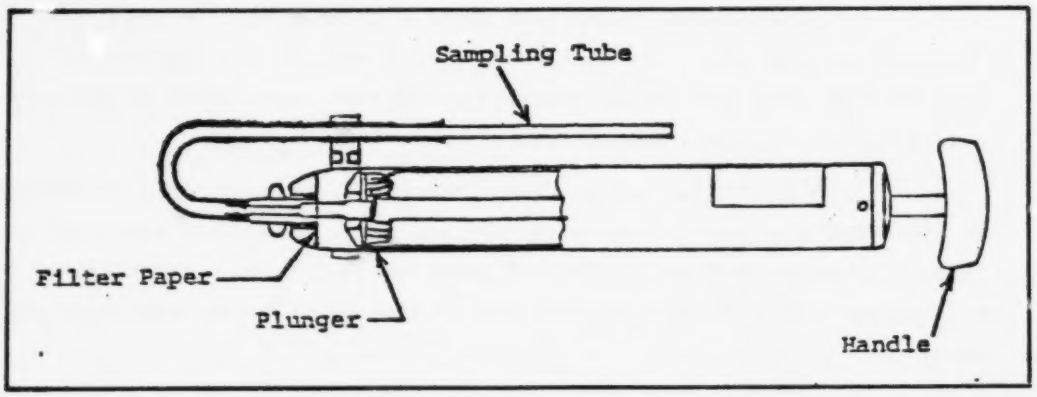


FIGURE 4-6. FIELD SERVICE TYPE SMOKE TESTER

The standard smoke scale consists of a series of ten spots numbered consecutively from 0 to 9, and ranging in equal photometric steps from white through neutral shades of gray to black. The standard spots are imprinted on white paper having an absolute surface reflectance of between 82.5 and 87.5%, determined photometrically. The smoke scale spot number is defined as the reduction (due to smoke) in the amount of light reflected by a spot divided by 10.

The smoke density is reported as the Smoke Spot Number of the spot on the standard smoke scale that most closely corresponds to the color of the soiled spot on the sample filter paper. Differences between two standard Smoke Spot Numbers are interpolated to the nearest half number.

4.10 Corrosion/Deposition Analysis

The method used to determine corrosion rates on boiler water tubes is to insert metal coupons representing a segment of water tube into the boiler furnace. The coupons are attached to the end of a probe which controls coupon temperature. These are inserted into the furnace through existing viewport openings and exposed to the corrosive action of the flue gas for about one month. The coupons are then removed and examined for corrosion effects.

The corrosion probes used in this program were designed and developed by KVB, Inc. The basic concept for cooling the coupons has evolved from early air cooled models through heat pipe models to the current reflux boiler concept shown in Figure 4-7.

In the reflux boiler design concept, condensed fluid is returned to the evaporator section via gravitational force instead of capillary action through a wetted wick as in the heat pipe design. This is accomplished by tipping the probe about 15 degrees off horizontal with the evaporator end down.

The evaporator section of the probe is insulated with wet felt. The function of the insulation is to reduce the heat load into the probe in those areas away from the coupon location. Thus, the coupons are the only evaporator segment exposed to the boiler heating environment.

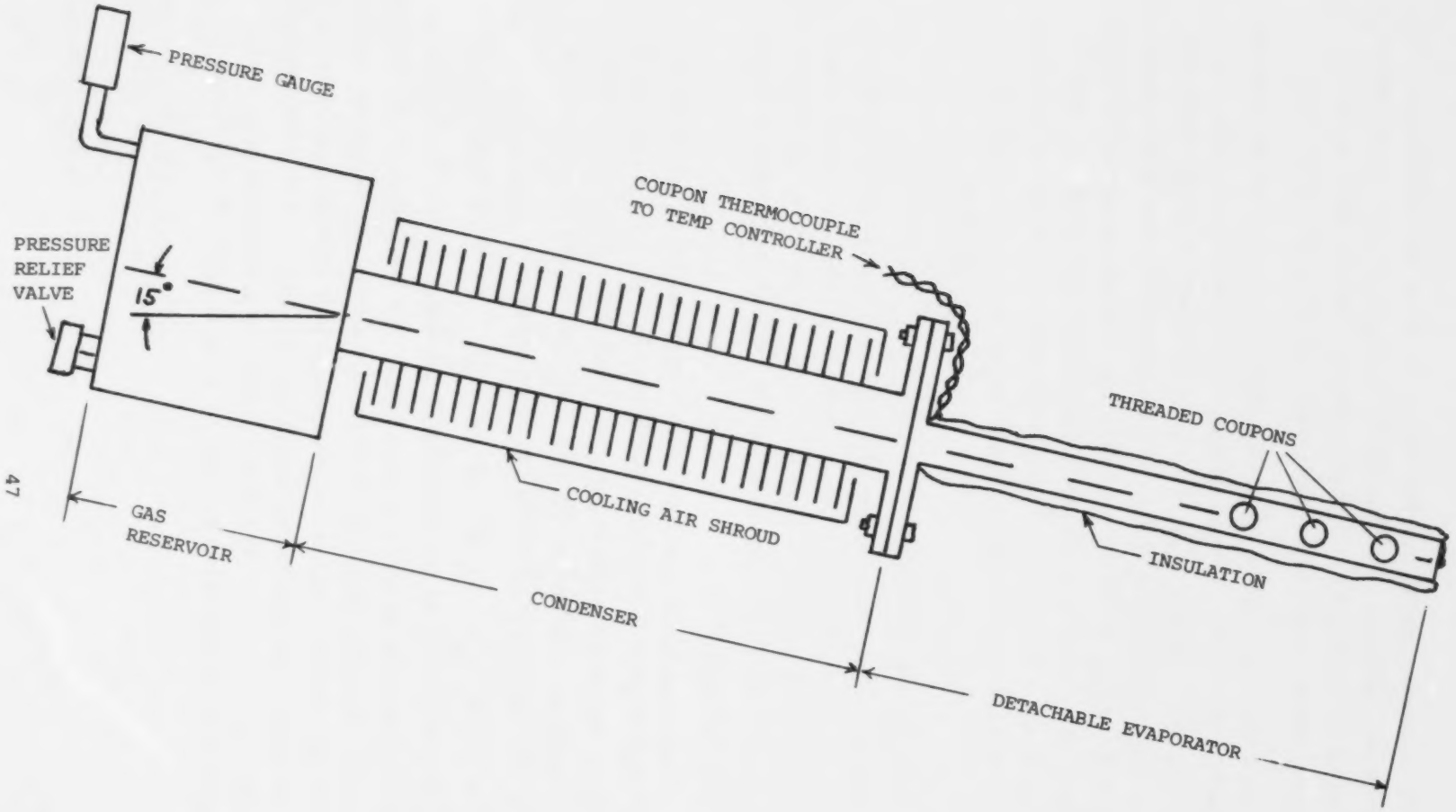


FIGURE 4-7. REFLUX BOILER CORROSION PROBE

15900-521

The condenser section of the corrosion probe has shrouded external fins and forced air cooling. The cooling air is supplied by a Rotran model TN 3AZ fan driven by an 85 watt, 155 VAC, 50/60 Hz, single phase motor. Thus, electrical power is the only requirement for operation of the unit.

New coupons are washed in acetone and air dried prior to weighing. After exposure in the boiler, the coupons are carefully cleaned with a wire brush. They are then cleaned in an ultrasonic bath of 1.0 normal inhibited hydrochloric acid. After rinsing with acetone, any remaining carbon deposits are removed with a brass brush. The coupons are next cleaned in an ultrasonic bath of benzene or trimethylene chloride for fifteen more minutes. They are then cleaned one more time in an ultrasonic bath of 1.0 normal inhibited hydrochloric acid and rinsed with acetone prior to drying and weighing.

4.11 Trace Species Measurement

The EPA (IERL-RTP) has developed the Source Assessment Sampling System (SASS) train for the collection of particulate and volatile matter in addition to gaseous samples (Figure 4-8). The "catch" from the SASS train can be analyzed for Poly Chlorinated Biphenyls (PCB's), Poly Organic Matter (POM) and other trace species.

In this system, a stainless steel heated probe is connected to an oven module containing three cyclones and a filter. Size fractionation is accomplished in the series cyclone portion of the SASS train, which incorporates the cyclones in series to provide large quantities of particulate matter which are classified by size into three ranges:

A) > 10μ B) 3μ to 10μ C) 1μ to 3μ

Together with a filter, a fourth cut (<1μ) is obtained. Volatile organic material is collected in an XAD-2 sorbent trap. The XAD-2 trap is an integral part of the gas treatment system which follows the oven containing the cyclone system. The gas treatment system is composed of four primary components: the gas conditioner, the XAD-2 absorbent trap, the aqueous condensate collector, and a temperature controller. The XAD-2 sorbent is a porous polymer resin with the capability of absorbing a broad range of organic species. Some

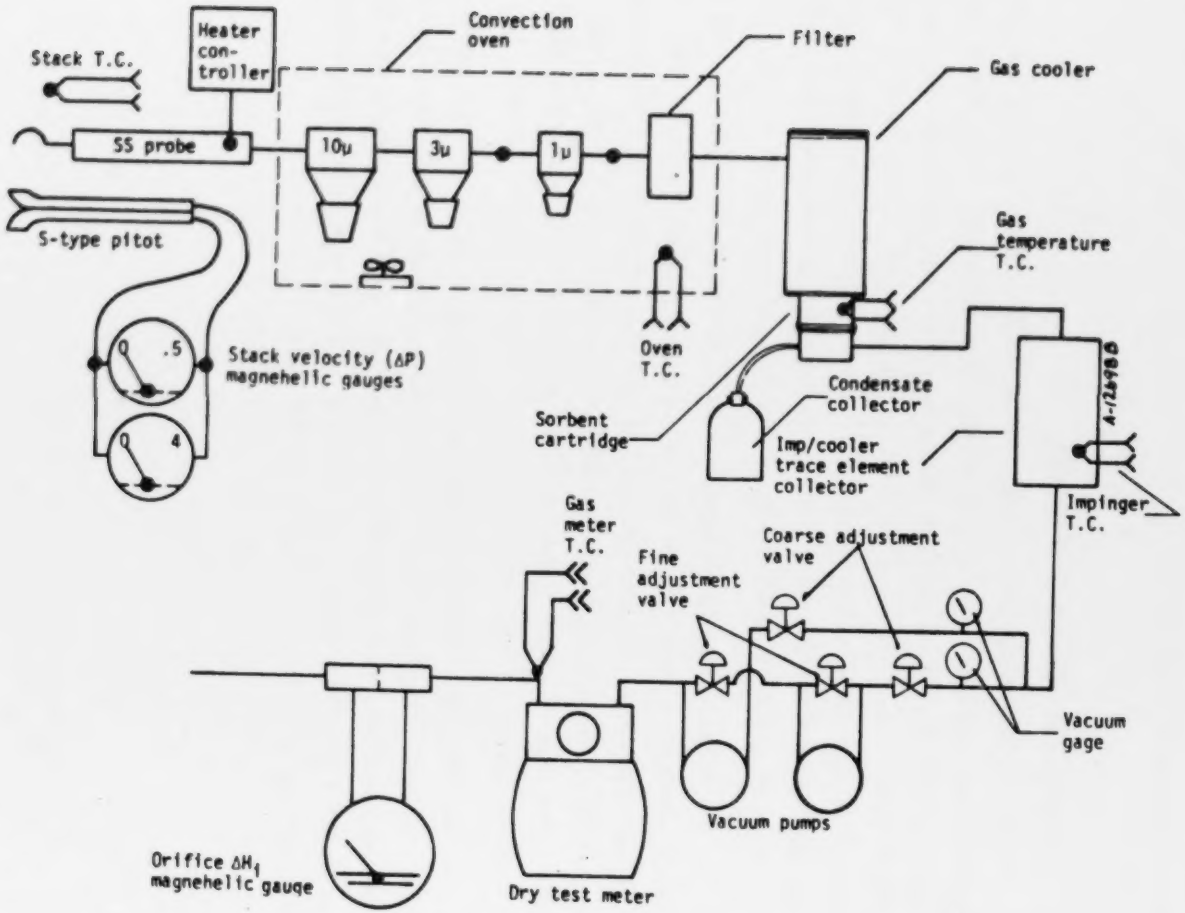


FIGURE 4-8. SOURCE ASSESSMENT SAMPLING SYSTEM FLOW DIAGRAM

KVB 15900-521

trapping of volatile inorganic species is also anticipated as a result of simple impaction. Volatile inorganic elements are collected in a series of impingers. The pumping capacity is supplied by a 10 cfm high volume vacuum pump, while required pressure, temperature, power and flow conditions are obtained from a main controller.

4.12 Flyash Resistivity Measurement

The Wahlco Resistivity Probe is an in situ field device for use in investigating problems with electrostatic precipitators. The means of collection is mechanical so no dust characteristics are destroyed during the sampling process. The probe can be used in temperatures up to 450°F. An integral cleaning system allows repeated tests in a single location without removing the probe from the duct. All instrumentation and probe hardware are contained in a single carrying case suitable as a shipping container.

The Resistivity Probe consists of a small cyclone inserted in the duct which collects a dust sample in a cylindrical stainless steel cup. A high voltage discharge pin mounted axially and electrically insulated from the cup serves as the energizing electrode. The steel cup serves as the receiver. The high voltage supply is held at 1,000 volts and resistivity of the collected sample is then determined as a function of the current.

An integral cleaning system permits emptying of the cup without removing the probe from the duct. Air is blown through a separate tube to a purge coil and then into the bottom of the cup, thus discharging the dust back into the flue gas stream. The purpose of the purge coil is to pre-heat incoming air to prevent condensation in the cup.

5.0 TEST RESULTS AND OBSERVATIONS

This Section presents the results of the tests performed on Boiler A. Observations are made regarding the influence on gaseous and particulate emissions and efficiency as the control parameters were varied. A total of forty tests were conducted in a defined test matrix to develop this data.

5.1 Overfire Air

Overfire air was varied to determine its effect on both emissions and boiler efficiency. It was found to effectively increase boiler efficiency and reduce particulate carryover by increasing combustible burnout in the flyash. High overfire air was also found to reduce carbon monoxide (an indicator of incomplete combustion) under those conditions (low excess air) where carbon monoxide is found; and, it was found to slightly decrease nitric oxide emissions from Boiler A.

The effectiveness of overfire air is based on how well it promotes mixing of the product gases in the flame zone. If local fuel rich pockets exist in the flame, combustion will be incomplete. Particulate emissions and combustible losses will increase. This increase will be evidenced by increasing CO levels and smoke. Turbulence induced by overfire air jets is effective if it penetrates deep into the flame zone. Some of the questions which this test program hopes to answer are:

A. Where in the flame zone is turbulence most effective? (Elevation off grate, angle, number of rows, spacing.)

B. What jet velocities are required for effective penetration? (This relates to fan sizing and header pressures required.)

C. Do extensive overfire air systems justify their cost?

Many of these questions will not be answered until data from several different overfire air systems are compared. Test results from Boiler A are presented in Tables 5-1 and 5-2, and in Figure 5-1. A discussion of this data follows.

TABLE 5-1

EFFECT OF OVERFIRE AIR ON EMISSIONS AND EFFICIENCY

	Set 1		Set 2		Set 3	
TEST NO.	28	29	35	34	39	38
Overfire Air Pressure, "H_2O	4	9	5.5	10.5	3	10
Firing Conditions						
Coal Supplier	Kem	Kem	Con	Con	Con	Con
Load, % of Capacity	84	85	76	76	60	59
Grate Heat Release, 10^3BTU/ft^2/hr	591	601	526	538	425	412
Coal Sizing, % passing 1/4"	44	49	52	53	74	72
Excess Air, %	22	21	38	38	29	28
Boiler Outlet Emissions						
Particulate Loading, lb/10^6BTU	20.5	15.4	20.5	11.9	13.3	6.3
Combustible Loading, lb/10^6BTU	13.5	8.4	14.3	7.9	6.3	3.9
Inorganic Ash Loading, lb/10^6BTU	7.0	7.0	6.2	4.0	7.0	2.4
Combustibles in Flyash, %	65.8	54.6	70.0	66.6	47.2	61.3
O_2, % (dry)	3.9	3.8	6.0	5.9	4.9	4.7
CO, ppm (dry) @ 3% O_2	1076	480	313	300	670	61
NO, ppm (dry) @ 3% O_2	408	398	394	353	335	313
Heat Losses,%						
Combustibles in Refuse	4.80	2.82	4.06	2.22	2.06	1.26
Dry Gas Loss	8.52	8.81	8.02	7.57	6.13	6.07
Boiler Efficiency	77.40	79.17	79.65	81.98	83.56	84.41

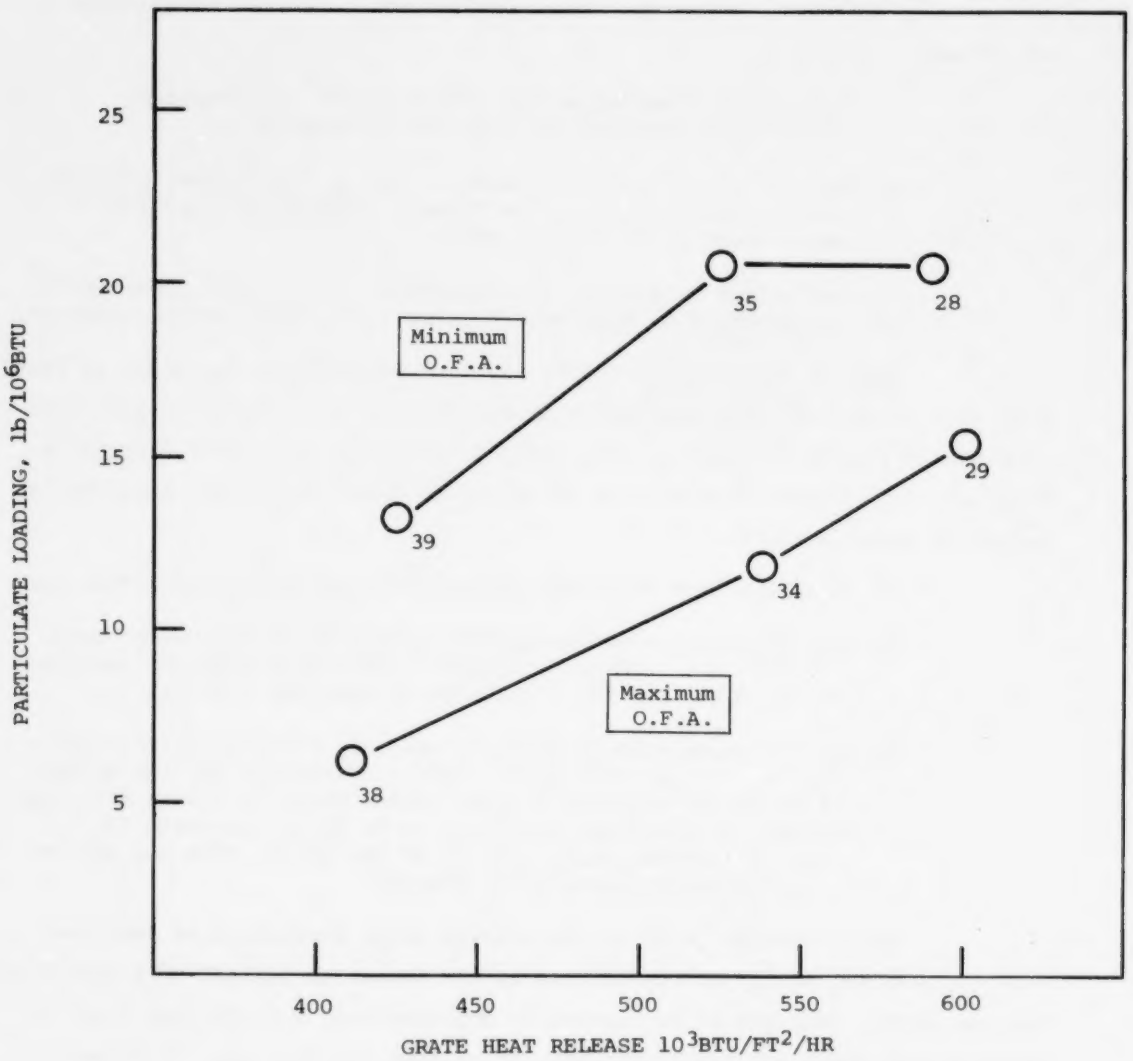


FIGURE 5-1. PARTICULATE LOADING VS OVERFIRE AIR

KVB 15900-521

Particulates were run during three sets of overfire air tests. This data is presented in Table 5-1. Load, excess air, coal type and sizing remained relatively constant for each set of tests. The two tests in each set were run as close to each other in time as was practical. The two tests in set 1 and set 3 were run on the same day. The two tests in set 2 were separated by 24 hours. From this data, the following general conclusions are drawn:

A. Particulate loading at the boiler outlet is reduced by 25-50% when overfire air pressure is doubled.

B. Much or all of this reduction is due to a more complete burnout of combustibles in the flyash. Combustible loading was reduced by an average 40%.

C. Combustion efficiency is improved by 0.8-2% when overfire air pressure is doubled. This may be a conservative estimate.

Gaseous emissions were also examined as possible functions of overfire air. This data is presented in Tables 5-1 and 5-2. In this case, more credibility should be given to tests 25 and 31 (Table 5-2) where changes in overfire air pressure were made at 10-20 minute intervals rather than over a period of hours or days.

In examining this data, two conclusions can be reached. They are:

A. Carbon monoxide concentration is reduced by the use of more overfire air. (This is a direct indication that the overfire air is doing its job of helping to complete combustion.)

B. Nitric oxide concentration is slightly reduced by increased overfire air on this unit. (After correcting for the effect of excess O_2 with the average trends shown in Figure 4-6, the average NO reduction was found to be 16 ppm or about 5%. Since the random variations in NO are large, this may not be a statistically significant change.)

The reduction in CO is encouraging as an indication of improved fuel burnout but really on its own has little impact on overall unit efficiency. For one thing, 1000 ppm of CO represents approximately a 0.33% heat loss. Under normal operating conditions with or without overfire air, CO emissions remain at or below this figure. Also, it has not been demonstrated that increased use of overfire air allows operation of the boiler at a lower total

TABLE 5-2

EFFECT OF OVERFIRE AIR ON GASEOUS EMISSIONS

TEST NO. 25, 74% LOAD, KEMMERER COAL
Vary all O.F. Air Headers Together

O.F. AIR, "H_2O	3	9
O_2, % (dry)	4.4	5.0
CO, PPM (dry) @ 3% O_2	802	450
NO, PPM (dry) @ 3% O_2	423	439

TEST NO. 31, 54% LOAD, KEMMERER COAL
Vary Front Lower O.F. Air, All Others 5"

O.F. AIR, "H_2O	2	5	10
O_2, % (dry)	2.6	2.6	2.6
CO, PPM (dry) @ 3% O_2	293	181	117
NO, PPM (dry) @ 3% O_2	196	196	201

TEST NO. 31, 54% LOAD, KEMMERER COAL
Vary Front Upper O.F. Air, All Others 5"

O.F. AIR, "H_2O	2	5	10
O_2, % (dry)	3.5	3.6	3.45
CO, PPM (dry) @ 3% O_2	231	233	231
NO, PPM (dry) @ 3% O_2	244	243	239

air (which would reduce the dry gas losses and improve unit efficiency). With the low-fusion coals tested on this unit, clinkering often sets the lower limit on undergrate air rather than the onset of smoke or CO.

A reduction in nitric oxide concentration by increased use of overfire air was expected. The reductions found on this unit averaged 16 ppm or about 5%. When firing coal, random variations in NO concentration of this magnitude often occur. Thus, 16 ppm may not be statistically significant.

One last comment should be made concerning the use of the upper rows of overfire air during low loads. The upper front row of overfire air jets was ineffective in reducing carbon monoxide during test number 31 (Table 5-2) at 54% of load capacity. It was observed during this test that the upper rows of jets were above the flame zone.

5.2 Flyash Reinjection

Flyash reinjection from the mechanical collector hopper on Boiler A was found to increase combustion efficiency by an estimated 1.5% or more. However, it also increased the particulate concentration at the boiler outlet by an average 33%. Increased tendency of grate clinkering with reinjection was not a problem during these tests although operators reported that this has been a problem in the past. In fact, it is because of the risk of clinkers that the mechanical collector ash is not routinely reinjected at Test Site A.

Three sets of tests were attempted on this unit to assess the effects of flyash reinjection on emissions and combustion efficiency. Tests 21 and 22 were run at 80% load on Kemmerer coal. Tests 23 and 24 were run the next day at 60% load on the same coal. Both sets were run with and without reinjection from the mechanical collector and showed similar results. Tests 36 and 37, which were run on Consolidation coal at 80% load, failed to produce satisfactory results. The unit tripped out briefly during Test No. 36 due to a low drum water level. Although testing was stopped until the load was restored, the load continued to fluctuate drastically during the remainder of the test.

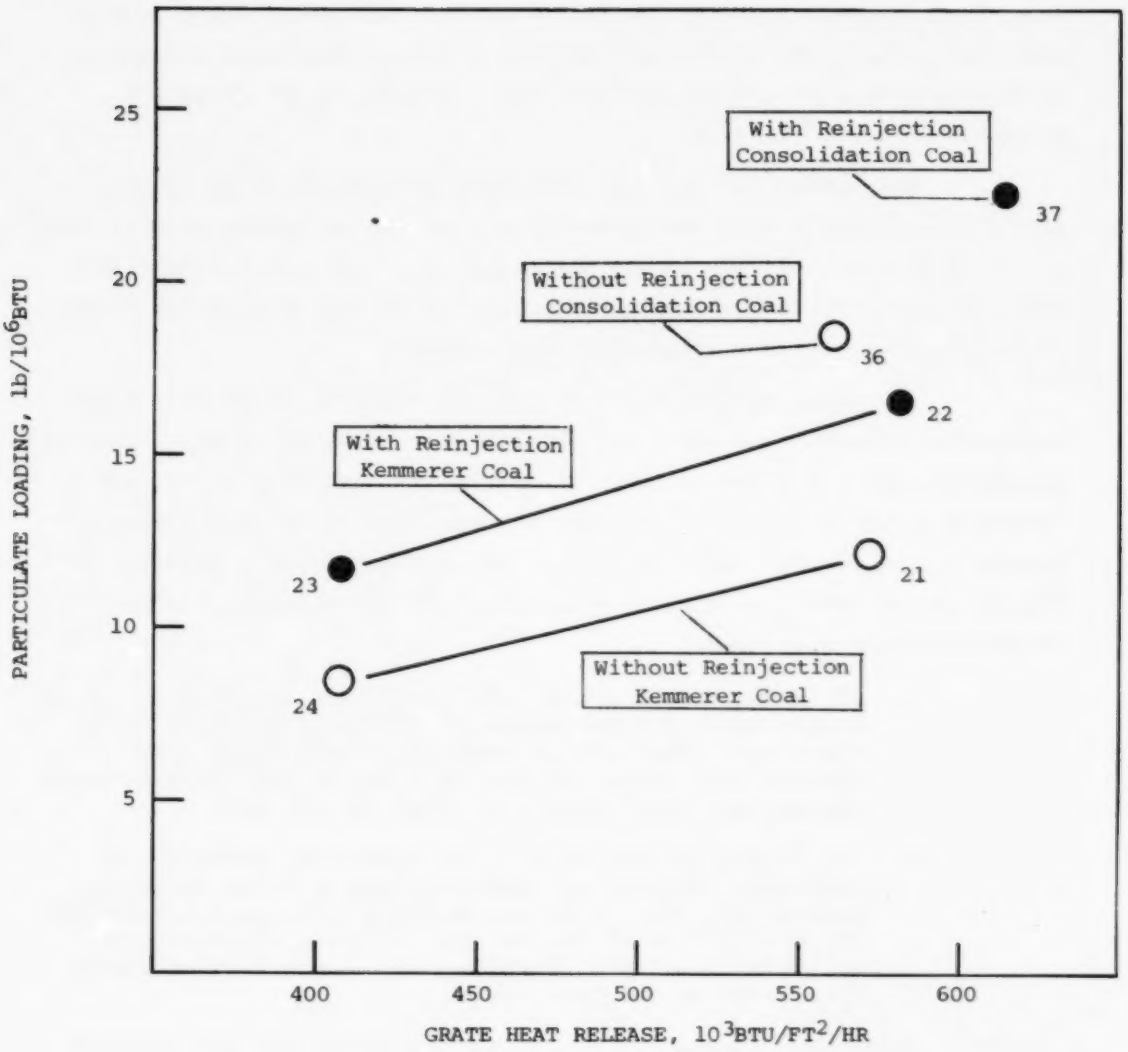


FIGURE 5-2. PARTICULATE LOADING VS FLYASH REINJECTION

These test results are presented in Table 5-3 and Figure 5-2. In Table 5-3 the emissions are given. Here it is shown that the percent combustibles in the boiler outlet ash decreased significantly while the total particulate loading increased. The net result was that the combustible loading at the boiler outlet, expressed in terms of mass per unit heat input, remained basically the same while the inorganic ash loading doubled when reinjecting. The logical explanation is that a considerable fraction of the reinjected ash is re-entrained, i.e., carried out of the boiler without settling on the grate.

When looking at the mass flow rates of the ash, it was found for Test 23, for example, that 587 lb/hr ash was entering the boiler with the fuel and 1,744 lb/hr ash was exiting the boiler outlet. This again shows that a substantial portion of the reinjected ash was circulating through the boiler continuously without being deposited on the grate.

Heat loss calculations were made to assess the effect of flyash reinjection from the mechanical collector on combustion efficiency. Several assumptions were necessary in order to compute the mass flow rate of ash collected by the multiclone. This measurement could not be made directly because of the physical impossibility of sampling particulates between the air heater (which reinjects continuously) and the multiclone inlet. The assumptions made were these:

A. 93% of the boiler outlet particulates are collected by the air heater hopper and the mechanical collector combined. This number was established by comparing boiler outlet dust loadings with mechanical collector outlet dust loadings under similar test conditions (i.e., Test 26A and 26B).

B. 70% of particulates entering the mechanical collector are collected. This is the design efficiency of the collector. Because less than 10% of the particles entering the collector are smaller than 10 microns, the collector efficiency may be greater than 70%. Therefore, the calculated combustible heat losses may be conservative.

Combustible contents of the flyash and bottom ash were measured directly. The heating value of the combustible material was calculated to be 14,250 BTU/lb. Appendix A-1 shows how this value was established. Flyash exiting the mechanical collector was assumed to have 45% less combustibles

TABLE 5-3

EFFECT OF FLYASH REINJECTION ON EMISSIONS AND EFFICIENCY

TEST NO.	Set 1		Set 2		Set 3	
	21	22	24	23	36	37
Reinjection from Multiclone	NO	YES	NO	YES	NO	YES
Firing Conditions						
Coal Supplier	Kem	Kem	Kem	Kem	Con	Con
Load, % of Capacity	82	83	59	59	80	87
Grate Heat Release, 10^3BTU/ft^2/hr	572	582	407	408	561	614
Coal Sizing, % passing 1/4"	45	70	67	49	50	70
Excess Air, %	26	23	29	26	27	31
Boiler Outlet Emissions						
Particulate Loading, lb/10^6BTU	12.1	16.6	8.4	11.7	18.5	22.5
Combustible Loading, lb/10^6BTU	8.7	9.7	5.1	5.1	11.1	14.8
Inorganic Ash Loading, lb/10^6BTU	3.4	6.9	3.3	6.6	7.4	7.7
Combustibles in Flyash, %	72.1	58.4	60.8	43.7	60.1	65.6
O_2, % (dry)	4.5	4.1	4.8	4.4	4.7	5.1
CO, ppm (dry) @ 3% O_2	998	1600	150	104	2000	276
NO, ppm (dry) @ 3% O_2	392	362	370	388	344	347
Heat Losses, %						
Combustibles in Collected Flyash	2.30	0.00	1.46	0.00	2.66	0.00
Combustibles in Emitted Flyash	0.57	0.72	0.36	0.35	0.66	0.82
Combustibles in Bottom Ash	0.01	0.01	0.01	0.01	0.03	0.04
Total Combustibles in Refuse	2.88	0.73	1.83	0.36	3.35	0.86
Dry Gas Loss	7.10	7.76	7.00	6.78	6.95	7.41
Boiler Efficiency	80.80	82.27	81.85	83.54	81.47	83.54

than at the boiler outlet in those instances where it was not measured. This value was established by comparing values from the two sample locations as tabulated in Table 2-4.

However the assumptions are drawn, flyash reinjection from the mechanical collector did improve combustion efficiency by as much as two percent. It also increased particulate loading at the boiler outlet by 33%. Its effect on particulate loading after the mechanical collector was not measured.

No trends were observed for nitric oxide or carbon monoxide emissions when flyash was reinjected from the dust collector (see Table 5-3).

5.3 Excess Air

At loads above 60% (400×10^3 BTU/ft^2/hr grate heat release) Boiler A was able to operate continuously without undesirable operating anomalies at 4.5 to 5.0% excess O_2. This is in the range of 25 to 30% excess air which is very good for a spreader stoker. This Section will discuss the influence of excess air on emissions and efficiency at Test Site A. Some general observations on the optimization of excess air for this boiler will also be discussed.

Total particulates were measured as a function of excess O_2 at the mechanical collector outlet and are shown graphically in Figure 5-3. It stands to reason that as combustion air velocity through the grate is increased, furnace velocities will increase and more ash from the grate and suspension burning will be carried out of the boiler. This was, in fact, observed at the mechanical collector outlet.

It was also observed that decreasing the excess O_2 reduced the heat loss due to combustibles in the refuse. As seen in Table 5-4, decreasing the excess oxygen an average 1.7% decreased the combustible content of the flyash and the particulate concentration, resulting in an average 0.8% increase in combustion efficiency.

TABLE 5-4

EFFECT OF EXCESS O_2 ON COMBUSTIBLES IN REFUSE

TEST NO.	Set 1		Set 2		Set 3	
	4	3	6	5	35	36
Excess O_2, % (dry)	6.3	4.1	5.8	4.1	6.0	4.7
Firing Conditions						
Coal Supplier	Stan	Stan	Stan	Stan	Con	Con
Load, % of Capacity	60	61	70	72	76	80
Grate Heat Release, 10^3BTU/ft^2/hr	404	421	433	494	526	561
Excess Air, %	41	23	37	23	38	27
Measured Combustibles, %						
Collected Flyash	--	--	--	--	70.0	68.5
Emitted Flyash	29.2	26.3	39.1	37.6	--	--
Bottom Ash	--	--	--	--	1.66	--
Heat Losses, %						
Combustibles in Collected Flyash	1.39*	1.12*	2.87*	1.73*	3.18	2.66
Combustibles in Emitted Flyash	0.33	0.26	0.68	0.41	0.79*	0.66*
Combustibles in Bottom Ash	0.03*	0.03*	0.03*	0.03*	0.09	0.03*
Total Combustibles in Refuse	1.75	1.41	3.58	2.17	4.06	3.35

* Indicates heat loss was estimated from relationships developed in Section 5.2

Carbon monoxide represents a heat loss but is more useful as an indicator of combustion problems. As a heat loss, it is generally very small. It has been calculated that 1000 ppm of CO represents 0.33% efficiency loss. Under normal and satisfactory operating conditions, carbon monoxide concentrations are well below this level.

Figure 5-4 presents all of the carbon monoxide data from Boiler A tests as a function of excess O_2. Percent steam loads are indicated for each test. The three test series specifically run to determine the relationship of CO to O_2 are connected by solid lines. The following observations are made:

A. Carbon monoxide begins to rise rapidly below 5-6% excess O_2 (about 30% excess air) at high loads.

B. The lower the load, the lower the excess O_2 before significant concentrations of CO are formed.

C. From an efficiency standpoint, CO would have to rise 2500 ppm per 1% O_2 decrease to offset the reduction in dry gas loss (discussed later). Thus, the breakeven point in terms of boiler efficiency is 1.5-2% O_2 at 60% load, 2.5-3% O_2 at 70% load, and 4.5-5% O_2 at 80% load. These points do not represent realistic operating conditions for reasons of clinkering, slagging and safety.

Figure 5-5 presents all the nitric oxide data from Boiler A as a function of excess O_2. Data points are also differentiated by load. The three tests designed specifically to find the relationship between NO and O_2 are connected by solid lines. Proposed nitric oxide trend lines are shown in Figure 4-6. These are based on the data presented in Figure 4-5. The following observations are made:

A. Nitric oxide concentration is primarily a function of excess O_2 on this unit. Nitric oxide concentration increases an average of 55 ppm for each one percent increase in O_2.

B. Nitric oxide is secondarily a function of boiler load. It increases an estimated 45 ppm for each ten percent increase in load although the exact amount is different under different conditions of load, O_2, etc.

C. Fuel properties, especially fuel nitrogen, may play an important role in nitric oxide formation but data on this variable is insufficient to make any correlation at Site A.

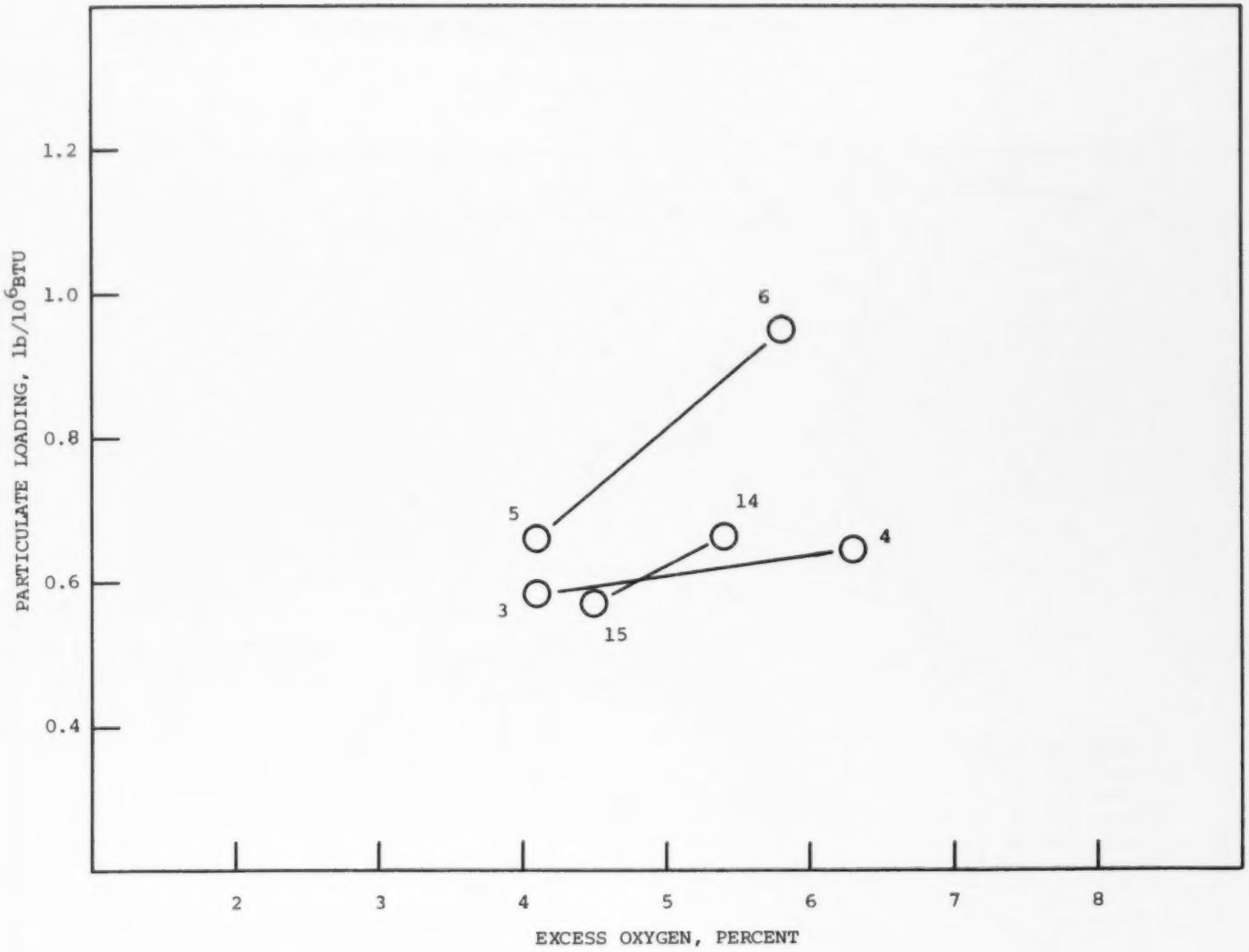


FIGURE 5-3. PARTICULATE LOADING VS EXCESS OXYGEN AT MECHANICAL COLLECTOR OUTLET

KVB 15900-521

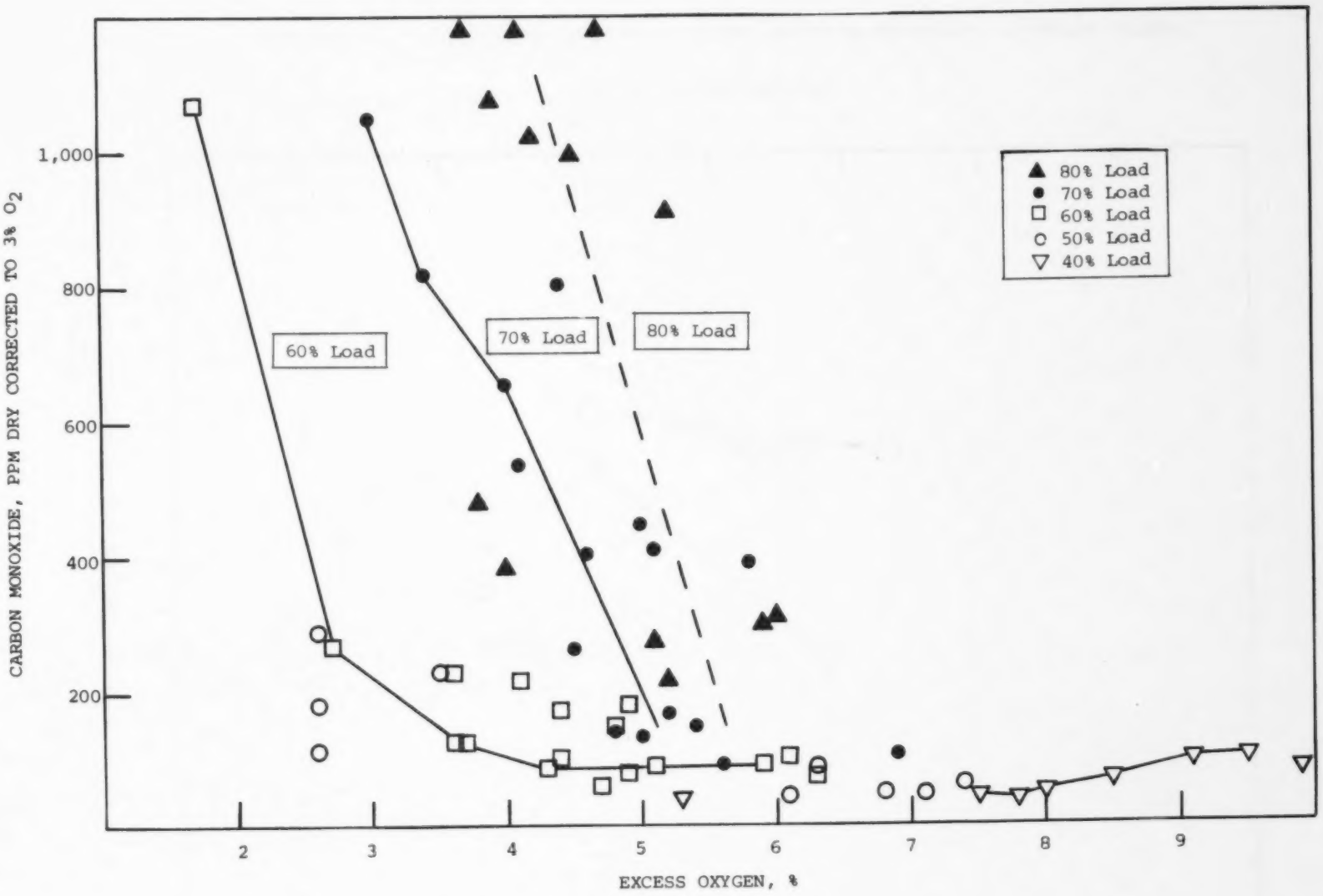


FIGURE 5-4. CARBON MONOXIDE VS EXCESS OXYGEN AND LOAD
TEST SITE A

KVB 15900-521

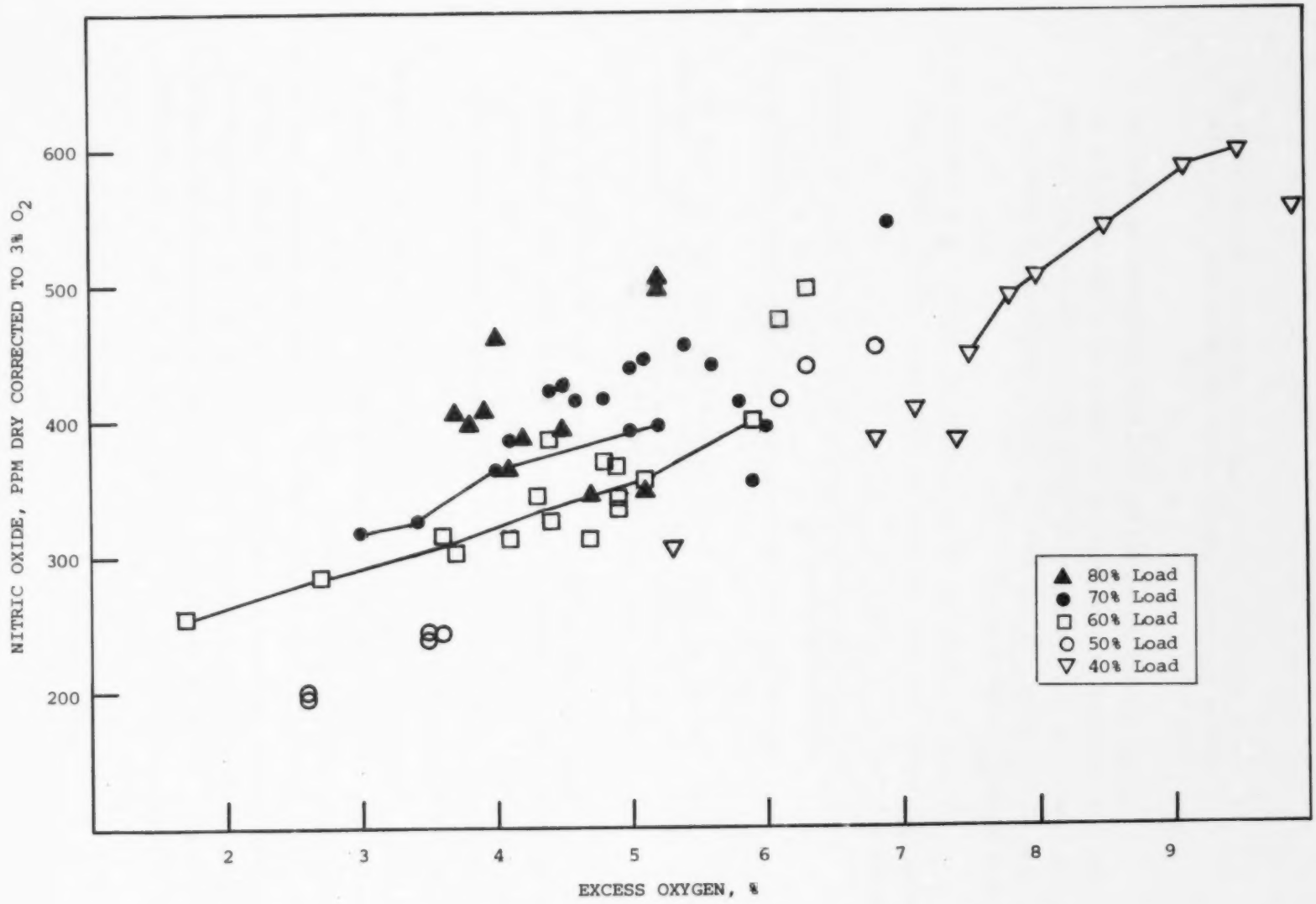


FIGURE 5-5. NITRIC OXIDE VS EXCESS OXYGEN AND LOAD
TEST SITE A

KVB 15900-521

D. It is theorized that on a day-to-day basis, coal moisture or sizing may significantly affect NOx emissions, even on the same coal.

Excess air influences boiler operating efficiency because the dry gas loss increases with an increase in excess air. The additional air absorbs heat which could otherwise be absorbed by the boiler, and carries the heat out the stack. In the same way, heat losses increase with increased moisture in the fuel.

Figure 5-7 shows the dry gas losses for Boiler A as a function of excess O_2. Boiler load and coal type are indicated. The following observations are made:

A. The dry gas loss increases by about 0.8% for each one percent increase in excess O_2.

B. The dry gas loss increases about 0.33% for each ten percent increase in load.

C. The dry gas loss is greater for the Stansbury coal than for the Consolidation coal. This is because of the lower moisture in the Consolidation coal. Stansbury averaged 19% moisture compared to 13% for Consolidation.

Excess Air Optimization. It is known that dry gas losses (heat out the stack) can be reduced by lowering the excess air, thus increasing unit efficiency. It is also known that there are practical lower limits to the excess air established by the onset of clinkering, smoking and/or high carbon monoxide emissions.

The key is to operate with the lowest practical excess air without getting into trouble. However, several problems force operators to operate consistently above optimum air levels. One problem is that the lower air limit is a variable. Some coals clinker up at higher air settings than others. Air settings which produced a clean stack one day may not the next. Another problem is that automatic controls cannot be relied upon to hold the air at low levels. Allowance must be made for air density changes due to temperature and pressure variations and for small mechanical deviations in the controls.

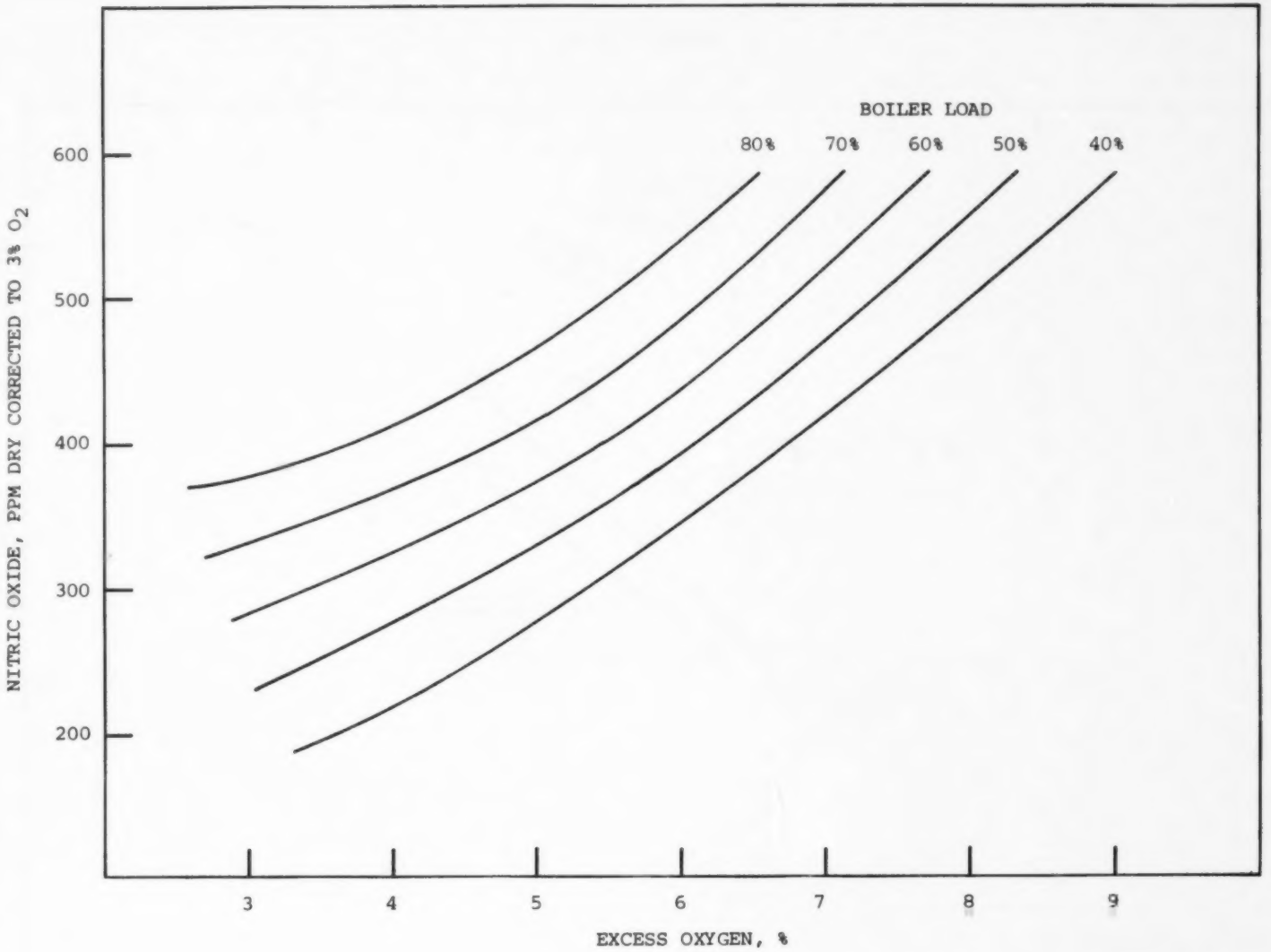


FIGURE 5-6. NITRIC OXIDE TRENDS VS EXCESS OXYGEN AND LOAD
TEST SITE A - ALL COALS

KVB 15900-521

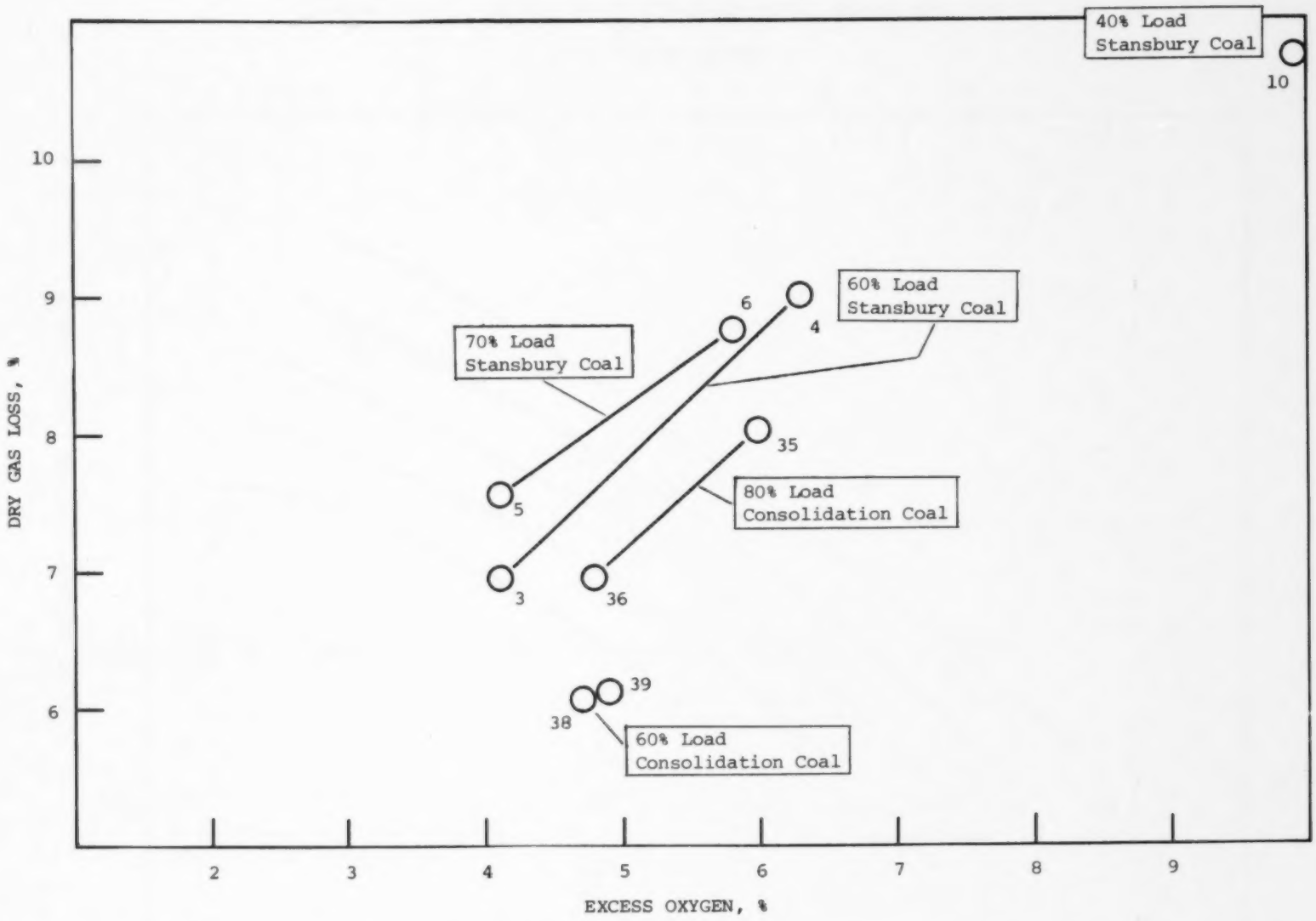


FIGURE 5-7. DRY GAS LOSS VS EXCESS OXYGEN, LOAD AND COAL
TEST SITE A

KVB 15900-521

Because of these two problems, it is very helpful for operators to have a reliable means of measuring the excess air on a regular basis. From the observations at Boiler A, the following suggestions are made:

A. The O_2 measurement should be made at the boiler outlet, not at the stack or after tubular air heaters where dilution will affect the readings.

B. Ideally, the sample should be pulled from several points across the duct. If a single point system is used, it should be centered as much as possible on the duct. Often, because of poor feeder adjustments, clinkers, coal size maldistribution, or other reasons, one side of the boiler will be burning well while the other side is unsatisfactory. This can lead to erroneous readings if a single sample point system is used.

C. A reliable continuous monitor should be used and checked periodically with an Orsat or other O_2 measuring device. Reliability in continuous monitors has been their biggest problem. Modern equipment is gradually reducing these problems. With proper maintenance and calibration checks these monitors are still better than intermittent sampling with an Orsat. When problems start, boiler performance often deteriorates rapidly. A continuous monitor would warn the operator in time to take corrective action.

D. A carbon monoxide monitor at the boiler outlet or an opacity monitor on the stack are indispensable companions to the O_2 monitor if optimum combustion conditions are to be maintained. They let the operator know the minute a problem develops.

5.4 Boiler Load

At Test Site A, peak boiler loads were not available. One reason was that process demand was seldom high enough to obtain peak loads. Also, the boiler would often run out of FD fan capacity before peak loads could be obtained. The latter may have been a control linkage problem. A study of emissions at and near peak loading would have been informative in establishing maximum heat release rates for grates and furnace volumes, and in establishing emissions at design load for comparison with other units.

The effect of boiler loading on particulate emissions in the 60-80% load range was studied at both the boiler outlet and mechanical collector outlet. From Figures 5-1 and 5-2 it can be seen how boiler load (expressed as grate heat release) affected emissions at the boiler outlet. At the mechanical collector outlet the data was very poorly defined, as seen in Figure 5-8. It is hard to discern what effect load has on particulate emissions but it appears to be much less sensitive to load than at the boiler outlet. This is to be expected. Dust loading increases with grate heat release but so does collector efficiency. The two effects tend to cancel each other out. The following exercise was undertaken to establish the extent of this relationship. The test pairs selected are considered representative of the particulate loading trend with changing grate heat release.

BOILER OUTLET

	Particulate Loading $lb/10^6 BTU$	Grate Heat Release $10^3 BTU/ft^2/hr$
Test 23	11.7	408
Test 22	16.6	582
% Increase	42	43

MECHANICAL COLLECTOR OUTLET

	Particulate Loading $lb/10^6 BTU$	Grate Heat Release $10^3 BTU/ft^2/hr$
Test 10	0.54	247
Test 5	0.66	494
% Increase	22	100

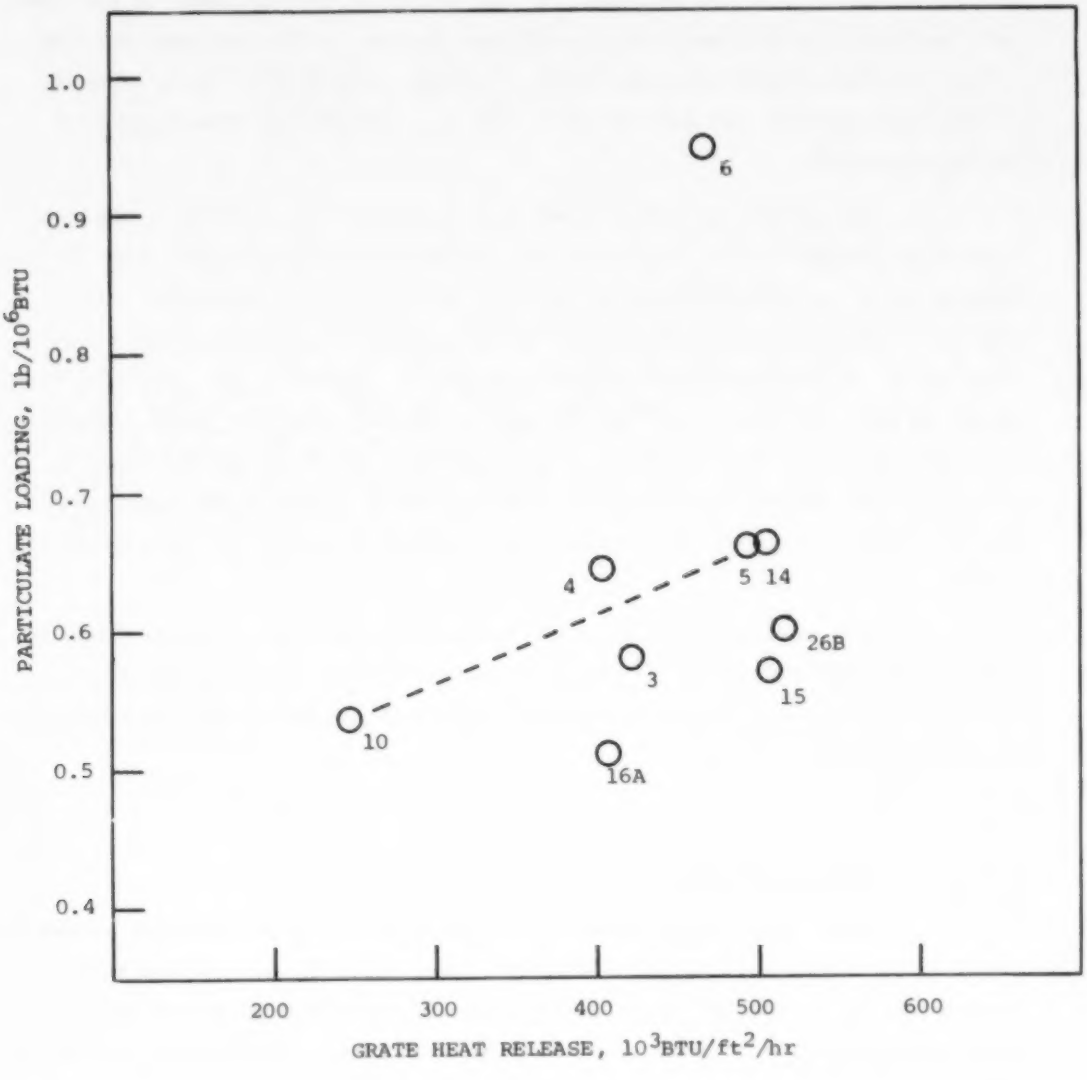


FIGURE 5-8. PARTICULATE LOADING AT THE MULTICLONE OUTLET VS GRATE HEAT RELEASE

From this exercise the following conclusions can be drawn. At the boiler outlet, a 10% increase in load brings a 10% increase in particulate loading. At the mechanical collector outlet, a 10% increase in load brings a 2.2% increase in particulate loading. Admittedly, this is only an estimate because the data trend is not well defined at the mechanical collector outlet.

The effect of boiler load on carbon monoxide emissions was presented in Section 5.3. To paraphrase, as excess air is reduced a point is reached at which carbon monoxide concentrations begin to increase very rapidly. This "carbon monoxide limit" is reached at higher excess oxygen conditions as the grate heat release increases (Figure 5-4). Thus, if carbon monoxide were the only limit to low air operation, the unit could operate at increasingly lower air as the load was reduced. This is not the case in actual boiler operation because clinkering on the grate often occurs before the CO limit is reached and necessitates higher air settings at the lower loads.

The effect of boiler load on nitric oxide emissions is shown in Figures 5-5 and 5-6 of the previous section. Nitric oxide concentration increases with load. This is a direct result of higher flame temperatures at higher loads.

5.5 Coal Properties

Three coals were studied at Test Site A. They differed in ash content, moisture, and sulfur. Complete coal analysis can be found in Tables 2-6, 2-7, 2-8, and 2-9. The analyses are shown on a constant heating value basis in Table 5-5 below so that direct comparisons can be made.

TABLE 5-5

COAL PROPERTIES CORRECTED TO A CONSTANT 10^6BTU BASIS

		Stansbury	Kemmerer	Consolidation
Moisture	lb/10^6BTU	13.6	18.1	12.1
Ash	lb/10^6BTU	5.8	3.4	7.4
Sulfur	lb/10^6BTU	0.88	0.61	0.38

The largest effect observed for fuel moisture in this test series was its detrimental effect on boiler efficiency. Figure 5-7 demonstrates that high moisture Kemmerer coal averaged about a one percent greater dry gas loss than the lower moisture Consolidation coal. Table 2-3 shows that the heat loss due to moisture in the fuel was an average 0.9% greater for the Kemmerer coal than for the Consolidation coal. These losses were expected and are well understood. The effect of fuel moisture on nitric oxide emissions and on particulate emissions will not be speculated on in this report. The reason is that this variable was not isolated from other fuel variables.

The high ash Consolidation coal emitted more particulates than the low ash Kemmerer coal. Figure 5-2 illustrates this observation. This should not be interpreted as an absolute relationship. Coking properties may play a significant role for other coals. Coal fines may also be a factor.

Sulfur oxides in the flue gas are directly related to the sulfur content of the coal. Generally, 80% or more of the fuel sulfur is converted to sulfur oxides and emitted while the remainder is retained in the ash. In Table 5-6 a sulfur balance was performed on the six SOx tests for which fuel sulfur and bottom ash sulfur data were available. It is clear that an insignificant fraction (1% or less) of the sulfur is retained in the bottom ash. One to four percent of the fuel sulfur is retained in the flyash at the boiler outlet. The remainder is converted to sulfur oxides and carried out with the flue gas.

Coal sizing was not one of the variables at Test Site A. The average and standard deviation of coal sieve test results for the Kemmerer and Consolidation coals are presented in Figures 5-9 and 5-10. They are both very similar. They are plotted along with the current ABMA recommended limits for stoker fired boilers.

Neither of these coals is a stoker coal. They both fall outside the recommended limits for spreader stokers on the high fines side. Yet, they burned quite well with a minimum of problems. The coal did pile up below the feeders occasionally. Past experience has shown that a high surface moisture will aggravate this piling problem, but the coals at Site A were not overly wet. At Test Site A, frequent checks by the operators prevented serious problems from developing.

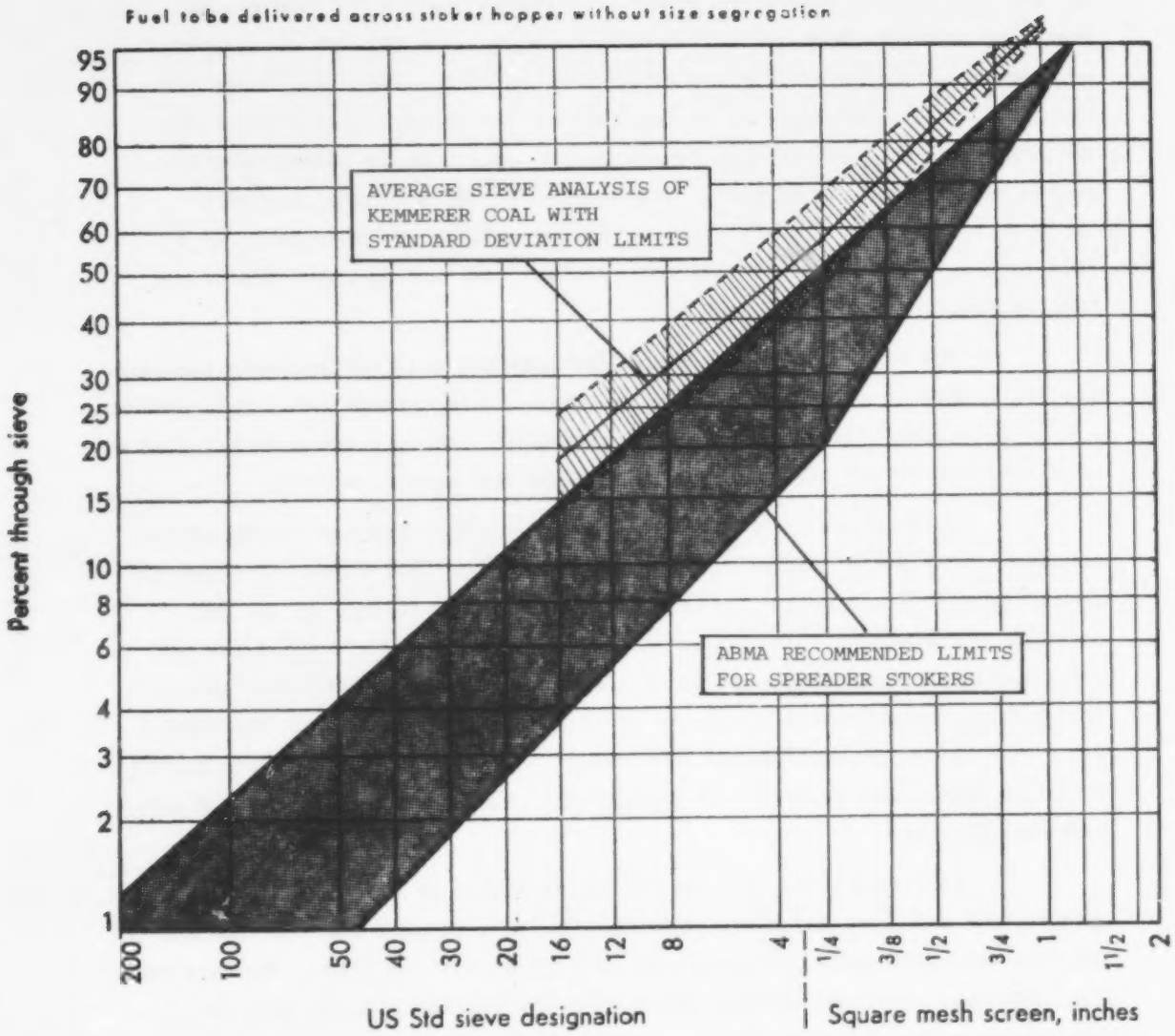


FIGURE 5-9

AVERAGE AND STANDARD DEVIATION OF 12 KEMMERER COAL SIEVE ANALYSIS VS ABMA RECOMMENDED LIMITS FOR SPREADER STOKERS

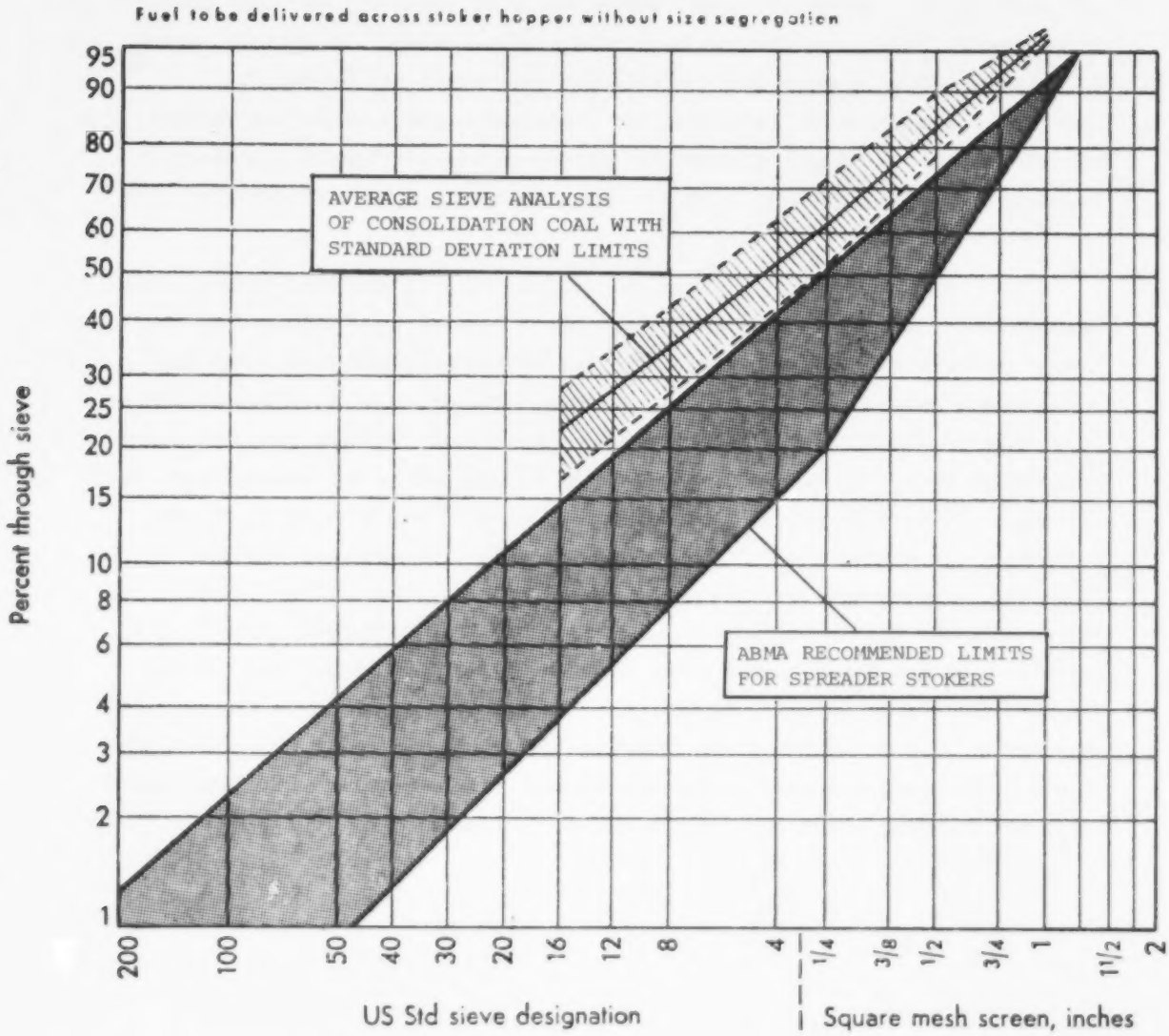


FIGURE 5-10

AVERAGE AND STANDARD DEVIATION OF 6 CONSOLIDATION COAL SIEVE ANALYSIS VS ABMA RECOMMENDED LIMITS FOR SPREADER STOKERS

The coal sampling technique should be discussed here to establish its credibility. Normally, coal samples would be taken off the coal scales apron feeder. Boiler A did not have coal scales. Also, a practical method of taking routine samples off the conveyor belt could not be found. Therefore, samples were taken from the observation ports above the feeders out of necessity. This coal sampling procedure was previously discussed in Section 4.6. The following test was run to determine the representativeness of these samples.

On September 14th there was a minor fire in the coal bunker. The bunkers were allowed to burn down overnight. As they were reloaded on the 15th, coal was sampled from the belt. The belt was stopped five times and each time a sample was obtained by taking all the material from an eighteen-inch section of the belt. The composite sample which weighed over 100 pounds was placed into a conical pile and divided by quartering and adding opposite quarters. When this procedure had produced a small enough sample, it was screened. In a couple of hours when the freshly bunkered coal started feeding, samples were taken from the seven feeders. The arrival of the fresh coal was distinguished by the surface moisture which was present as a result of a rain on September 14th. The composite feed sample was treated in the same manner as the belt sample. The results are shown in Figure 5-11. The feeder sample had 60% fines (passing 1/4") while the belt sample had 65% fines. The samples appear to be very similar. Subsequent samples were taken from the feeders, since the bunkers are not burned down every day.

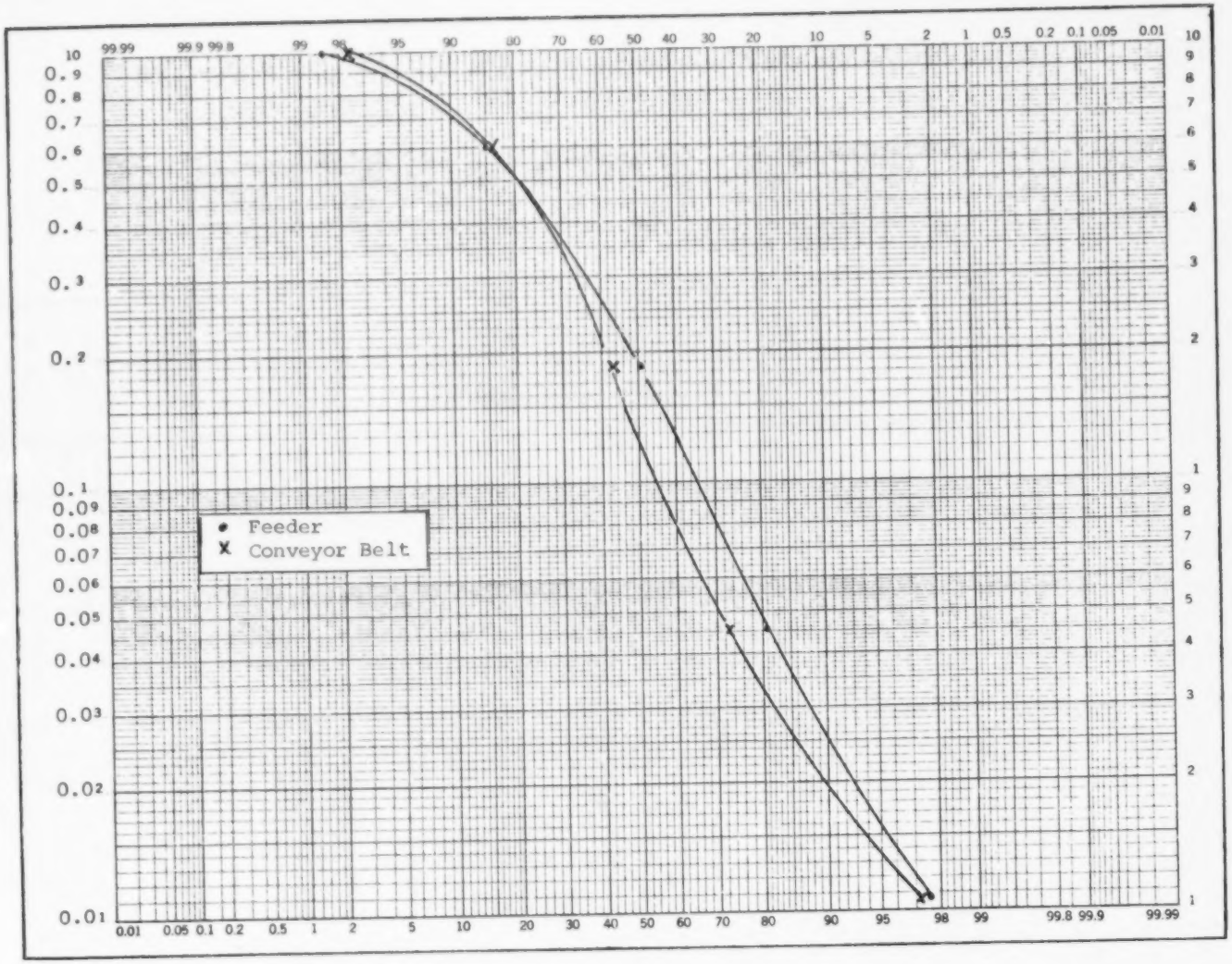


FIGURE 5-11. COMPARISON OF TWO COAL SAMPLING LOCATIONS FOR SIEVE TESTING

KVB 15900-521

TABLE 5-6

SULFUR BALANCE SUMMARY
TEST SITE A

Test No.	Load %	O_2 %	SULFUR IN FUEL		SULFUR IN BOTTOM ASH			SULFUR IN FLYASH			SULFUR EMISSIONS		
			Fuel Sulfur %	As SO_2 lb/10^6BTU	Ash Sulfur %	As SO_2 lb/10^6BTU	Retention %	Ash Sulfur %	As SO_2 lb/10^6BTU	Retention %	SOx ppm/dry	SOx lb/10^6BTU	Fuel Sulfur Emitted, %
						STANSBURY COAL							
8	65	4.8	0.97	1.790	0.05	0.005	0.3	--	--	--	754	1.452	81
9	61	4.9	0.91	1.711	0.06	0.007	0.4	--	--	--	796	1.533	90
12	45	6.1	0.90	1.670	0.06	0.005	0.3	--	--	--	795	1.531	92
18	46	7.4	0.88	1.670	0.16	0.018	1.1	--	--	--	896	1.726	103
						CONSOLIDATION COAL							
34	76	5.9	0.73	1.386	0.01	0.002	0.1	0.37	.016	1.2	514	0.975	70
35	76	6.0	0.35	0.655	0.02	0.003	0.5	0.32	.025	3.8	417	0.791	121

6.0 SPECIAL TESTS

This Section presents the results of certain tests which because of their unique nature are kept separate from the main body of test results in Section 5.0.

6.1 Particle Size Distribution

Figure 6-1 shows the particle size distribution at the boiler outlet, the multiclone outlet and the electrostatic precipitator outlet of Boiler A. Four test methods were used to compose this graph. Each method had its advantages and disadvantages. None were ideal. It is felt important enough for future particle size testing to devote the remainder of this section to a discussion of these four test methods and their peculiarities.

There are several developed technologies for measuring particle sizing. However, very little particle sizing has been done at the boiler outlet of spreader stokers. Therefore, the technology in this area is not developed. At the start of this program, KVB consulted several sources including Southern Research Institute and the Process Measurements Branch of EPA's Industrial Environmental Research Laboratories - RTP. Both sources recommended the Brink Cascade Impactor equipped with a precutter cyclone as the best available technology to use. Therefore, a Brink Impactor was obtained by KVB for these tests.

Unfortunately, the Brink Cascade Impactor was found to be unsatisfactory for measuring particle size distributions at the outlet of Boiler A. The particles being measured were often as large as the sample nozzle (1.5-2.0 mm) making it nearly impossible to obtain a representative sample. Also, the impaction range of the Brink is 0.3 to 3.0 microns which included only the lower six percent or less of the total catch.

Three alternatives to the Brink Cascade Impactor were investigated at Test Site A. They were the SASS cyclones, the BAHCO centrifugal classifier, and the Coulter Counter. All four methods are discussed below.

Coulter Counter. With this method a sample is collected and sent to a laboratory for analysis. Its range of size classification is greatest

of all methods tested. Ten to 250 microns are measured with the counter. Data from 250 to 1,680 microns is obtained by means of a sieve analysis. The lower size detection limit of this device is set by the largest particles being measured. Although it can measure particles in the sub-micron range, the large size of the particles collected from Boiler A dictated using a 560 micron aperature on the counter. This limited the lower end of its detection range to ten microns.

Figures 6-2 and 6-3 present the Coulter Counter test data and compare it with the BAHCO Classifier test data for two ash samples. The loss of particle detection below ten microns is evident in these two figures. Thus, the Coulter Counter is not a viable sizing device when used by itself if there is interest in particle size distribution below ten microns.

BAHCO Classifier. This method, described in PTC 28, has the advantage of being recognized in the power industry as an established particle sizing procedure. However, like the Coulter Counter, BAHCO classification is a laboratory technique. Thus, it shares some of the same limitations as the Coulter Counter and all other laboratory techniques. One limitation is the difficulty in collecting particles below about five microns. These usually end up on a final filter or are discarded entirely, thus changing the size distribution of the sample catch. Also, because the sample catch must be transported and stored, the particle sizes may be reduced (by breaking) or increased (by agglomeration).

The range of size classification for the BAHCO is approximately 1.5 to 25 microns. To compare the BAHCO Classifier with the Coulter Counter, two flyash samples were split with half of each sample being size classified by each of these two methods. The results are presented in Figures 6-2 and 6-3. By combining the two methods, the Coulter Counter's loss of detection below ten microns can be corrected as it was in the composite plot shown in Figure 6-1.

SASS Cyclones. The SASS train contains three cyclones upstream of the filter which are sized for ten, three and one micron cut points. This device has an advantage over the previous two devices in that all data reduction can be done in the field. It has the disadvantage of being a single

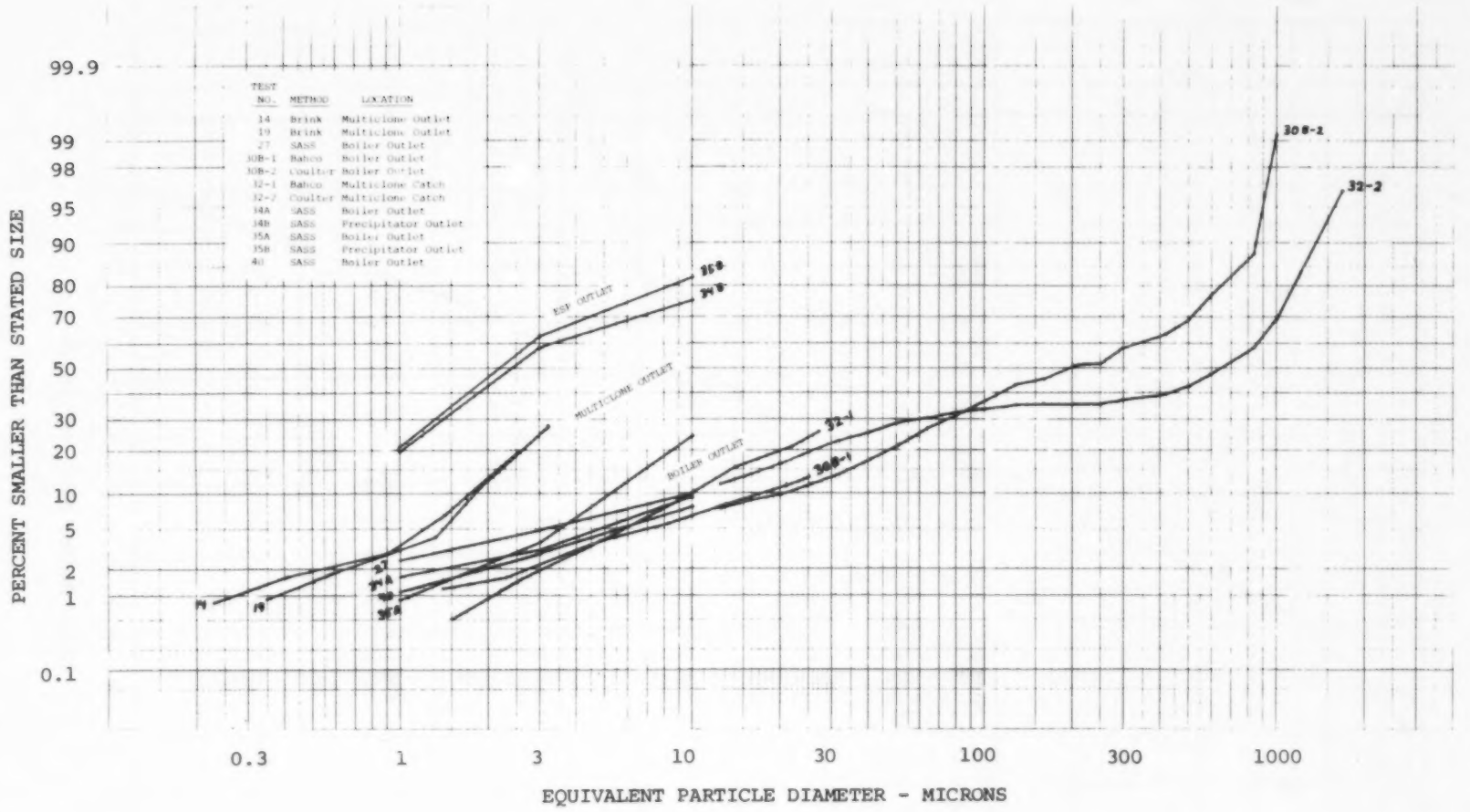


FIGURE 6-1. COMPOSITE OF ALL PARTICLE SIZING TESTS AT SITE A

KVB 15900-521

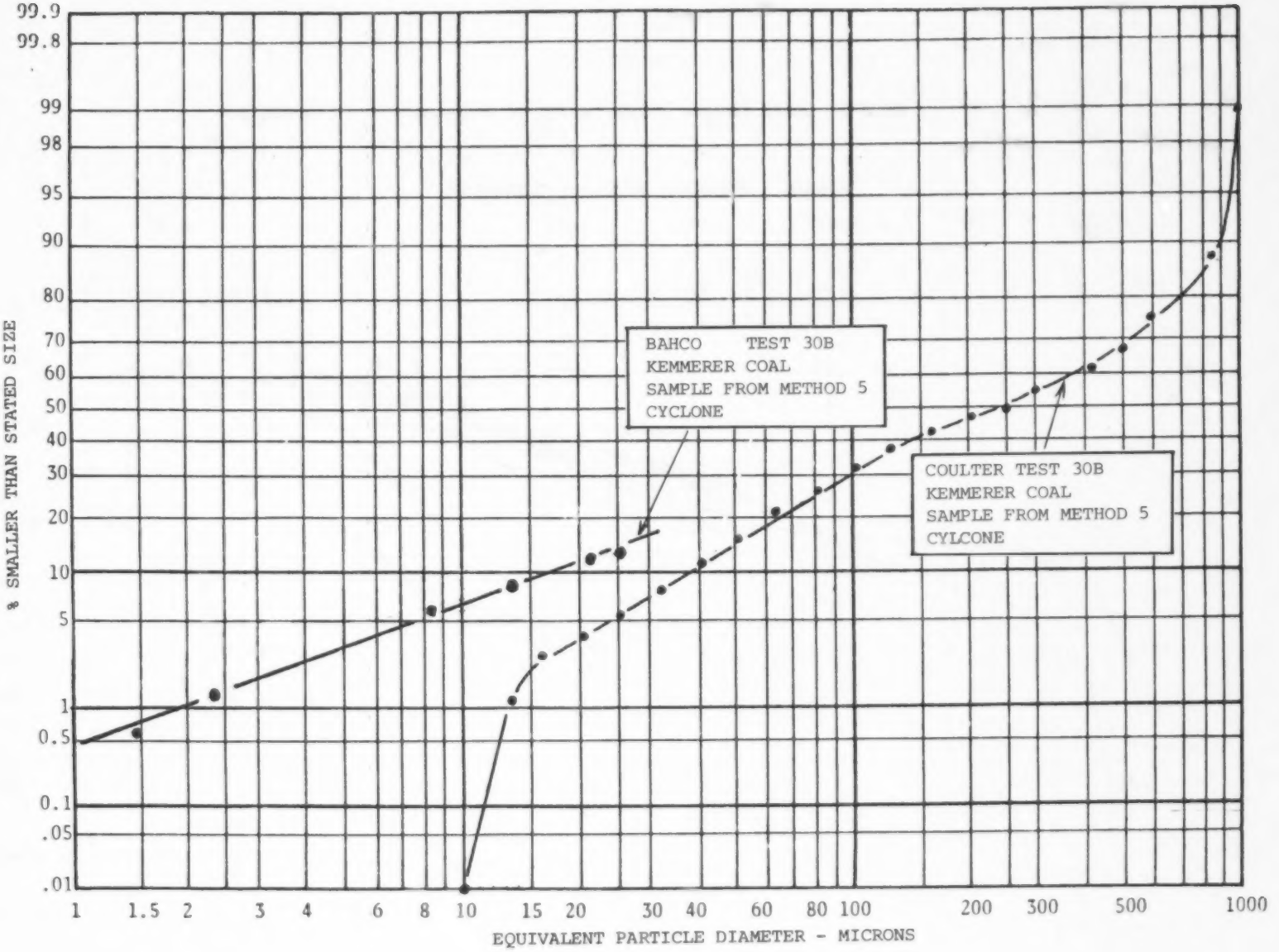


FIGURE 6-2 COMPARISON OF PARTICLE SIZING TECHNIQUES

KVB 15900-521

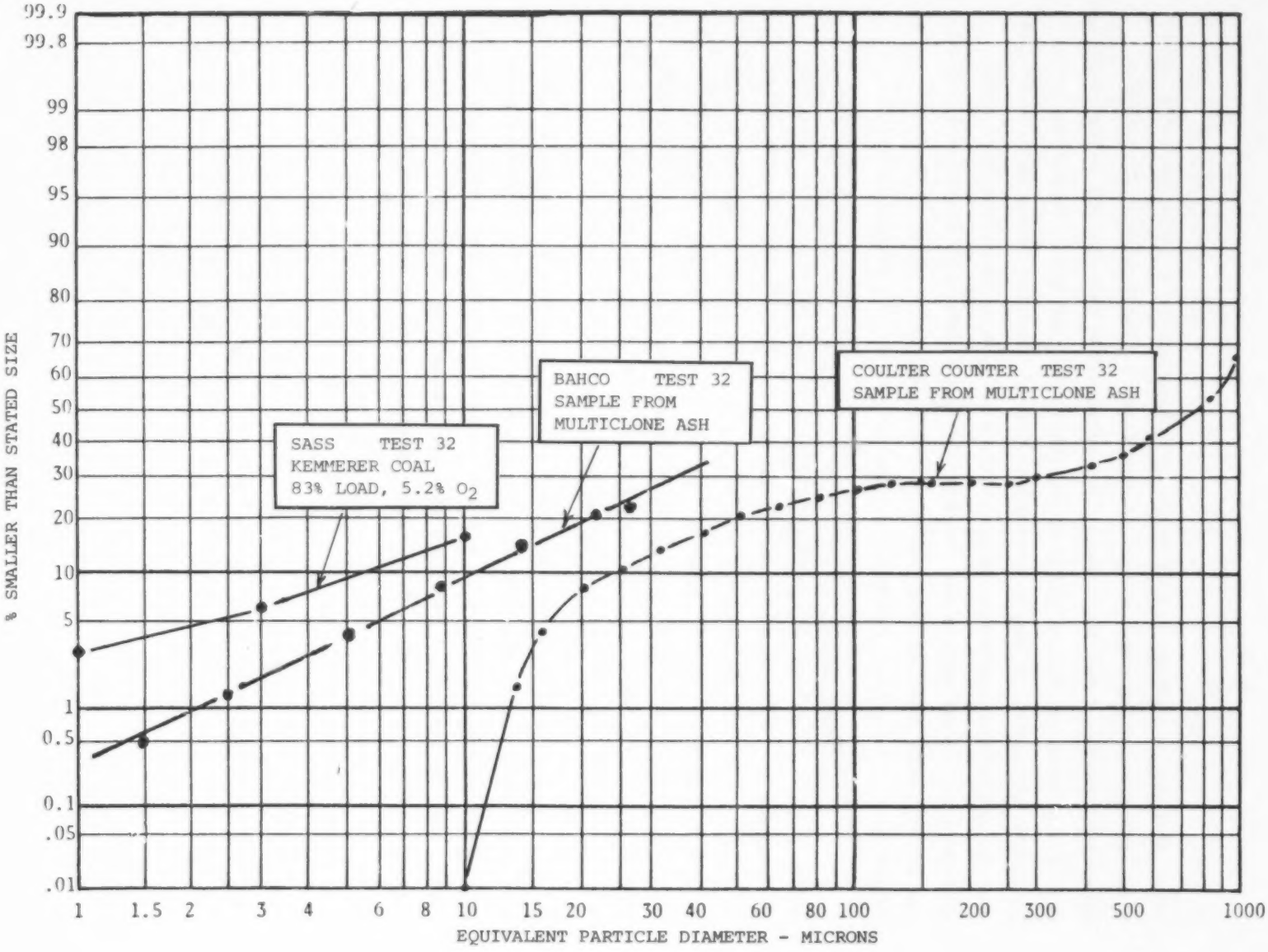


FIGURE 6-3 COMPARISON OF PARTICLE SIZING TECHNIQUES

KVB 15900-521

point sampler, a problem shared by Cascade impactors. A large particle size stratification is expected at any stoker fired boiler outlet. This is because of turns in the gas stream, and because the particulate matter contains relatively large particles which do not turn with the gas. Therefore, it is always desirable to sample at several points over the cross section of the duct to get a representative sample. The gravimetric data from five SASS catches are plotted beside the Coulter and BAHCO curves in Figure 6-1. Also, one of the SASS tests is compared with the BAHCO and Coulter methods in Figure 6-3. Its higher fines can be attributed to the sample location.

Brink Impactor. Impactors have an advantage over competing techniques in that they are compact and can be inserted directly into the duct, avoiding the problem of sample loss in a probe. Size classification is made in the duct so that all conditions are realistic. Impaction also allows all data reduction to be done in the field. The main disadvantage of the Brink impactor is its restricted range of classification (0.3 to three microns) and its demonstrated inability to collect the largest particles in the flue gas stream at the boiler outlet of spreader stokers.

Although impaction sampling was not feasible at the boiler outlet, two tests were run at the mechanical collector outlet. This data is presented in Figure 6-1. Test 14 was run at 69% load with 35% excess air (5.6% O_2). Test 19 was run at 44% load with 46% excess air (6.8% O_2). Both tests were with Stansbury coal. Both tests showed a similar size distribution.

6.2 Size Segregation of Combustible Material

A multiclone ash sample from Test 24 was cut into three size fractions. Each fraction was analyzed for percent combustibles. The test results are presented in Table 6-1 below.

TABLE 6-1

VARIATION OF PERCENT COMBUSTIBLES WITH PARTICLE SIZE

Screen Size	Weight, %	% Ash (Dry)	% Combustibles (Dry)
+ 20 mesh	4.3	27.44	72.56
20 x 100 mesh	34.4	38.68	61.32
100 mesh x 0	61.3	95.00	5.00
Weighted Average		72.72	27.28

In this test, the smaller particles had the smaller combustible fraction. This agrees with the combustible data shown in Table 2-4 of the appendix where flyash at the boiler outlet averaged 58.4% combustibles compared to only 30.3% at the multiclone outlet after the largest particles had been removed.

6.3 Efficiency of Pollution Control Equipment

Several test series were run to measure the efficiency of the pollution control equipment at Test Site A. The results are presented in Table 6-2. A brief discussion follows.

The mechanical collector could not be isolated from the air heater hopper for testing. However, the efficiency of the two combined was found to be 93.9% at 70% load on Kemmerer coal. The mechanical collector by itself has a design efficiency of 70%.

The electrostatic precipitator (ESP) was found to be 96.8% efficient in removing particulates at 60% load on a coal believed to be a blend of Stansbury and Kemmerer coals. Its design efficiency is 97.83%.

TABLE 6-2

EFFICIENCY OF POLLUTION CONTROL EQUIPMENT

Test No.	Location	Load %	Excess O_2 %	Part. Loading $lb/10^6BTU$	Equipment, Efficiency and Coal
26A	Boiler Outlet	70	5.1	9.77	Air Heater & Mech. Coll.
26B	Mech. Coll. Outlet	74	4.6	0.600	93.9% efficient, Kem Coal
16A	Mech Coll. Outlet	59	6.1	0.512	Electrostatic Precipitator
16B	ESP Outlet	59	6.1	0.0166	96.8% efficient, Coal blend
17A	ESP Outlet	52	6.3	0.0194	Sulfur Scrubber
17B	Stack	52	6.3	0.0128	34% part removal, Coal blend
34A	Boiler Outlet	76	5.9	11.89	A.H., Mech Coll & ESP
34B	ESP Outlet	76	5.9	0.0576	99.5% eff, Consolidation
35A	Boiler Outlet	76	6.0	20.48	A.H. Mech Coll & ESP
35B	ESP Outlet	76	6.0	0.0296	99.86% eff, Consolidation
				SOx $lb/10^6BTU$	
8A	Mech Coll Outlet	65	4.8	1.452	Sulfur Scrubber, 59.6% eff
8B	Stack	52	6.8	0.586	Stansbury Coal
18A	Mech Coll Outlet	46	7.4	1.726	Sulfur Scrubber, 64.5% eff
18B	Stack	46	7.1	0.612	Stansbury Coal

If the air heater and mechanical collector together remove 93.9% of the particulates and the precipitator removes an additional 96.8%, then the combination should remove 99.8% of the particulates exiting the boiler.

During Tests 34 and 35 particulate loading was measured simultaneously across the air heater, mechanical collector and the precipitator. During these tests, three of the four precipitator fields were not operating. The measured efficiencies were 99.5 and 99.86% respectively at 76% load on the Consolidation coal.

The sulfur scrubber was found to be 34% efficient in removing particulates at 50% load on a blend of Stansbury and Kemmerer coals.

In two tests the sulfur scrubber was found to remove 59.7 and 64.5% of the sulfur in the flue gas. This is well below the 90% design efficiency of the unit. Test loads were 60% and 46% respectively. In both cases Stansbury coal (about one percent sulfur) was burned.

6.4 Modified Smoke Spot Number

Smoke spot readings were taken with a Bacharach Smoke Spot tester at the boiler outlet. The pump was stroked once or twice each time as opposed to the specified ten times required on an oil fired unit by ASTM D2156-65. The smoke spot results are tabulated in Table 6-3 below. They are plotted against particulate loading in Figure 6-4, and against combustible loading in Figure 6-5.

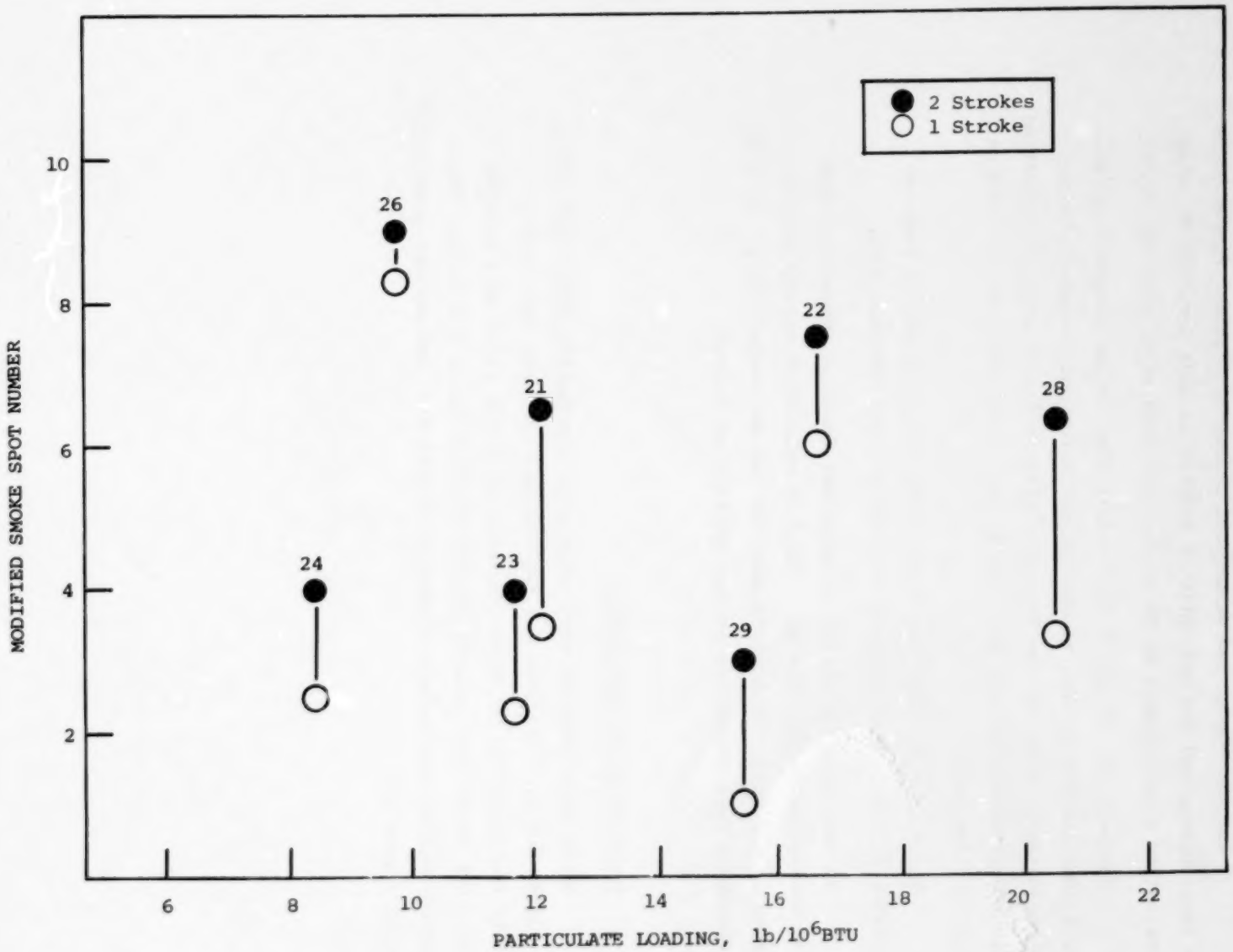


FIGURE 6-4. MODIFIED SMOKE SPOT NUMBER VS PARTICULATE LOADING

KVB 15900-521

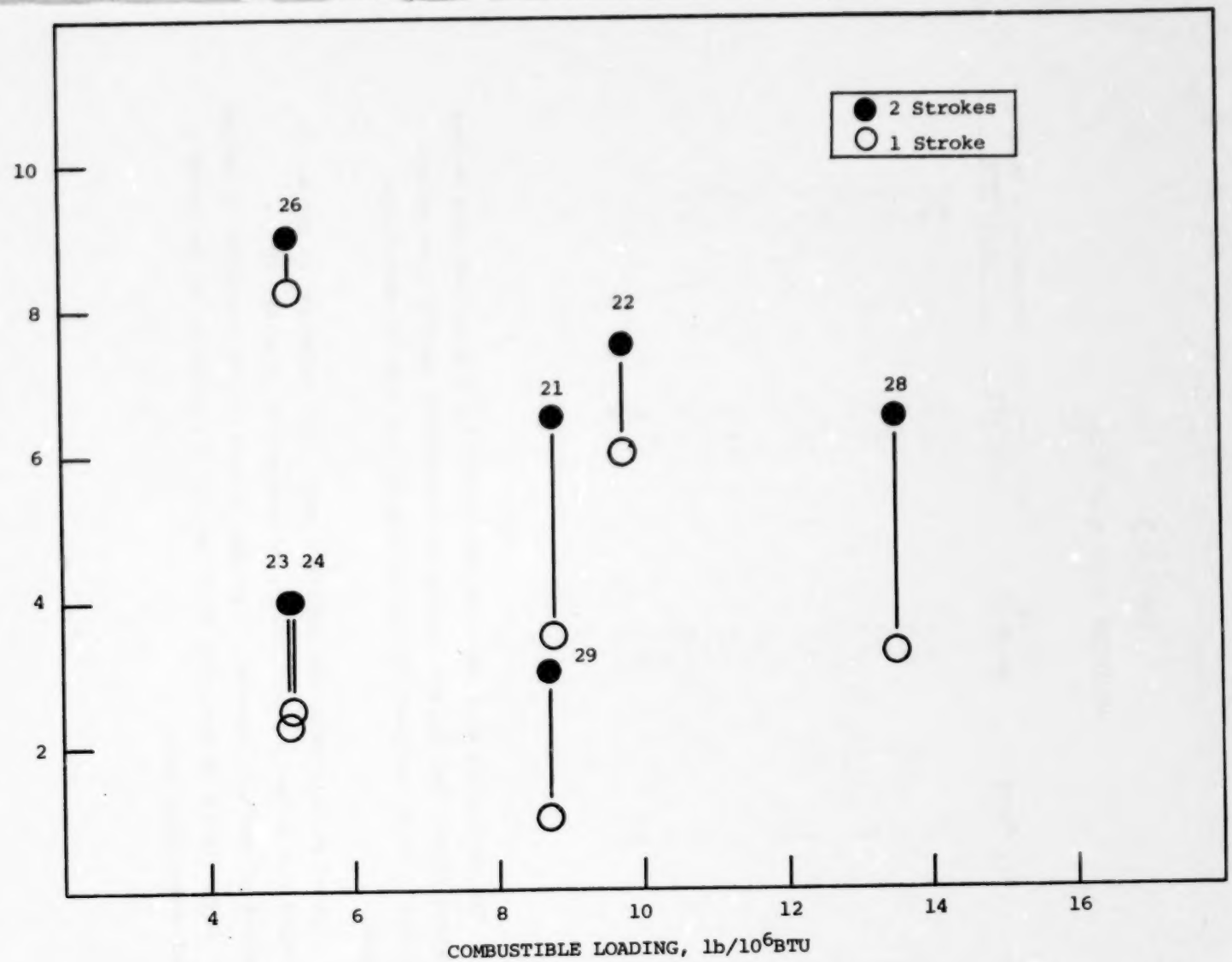


FIGURE 6-5. MODIFIED SMOKE SPOT NUMBER VS COMBUSTIBLE LOADING

KVB 15900-521

TABLE 6-3

MODIFIED SMOKE SPOT DATA

Test No.	No. Pumps	Average Reading	Part. Loading lb/10^6BTU	Combustible Loading lb/10^6BTU
21	1	3.5	12.1	8.7
22	1	6.0	16.6	9.7
23	1	2.3	11.7	5.1
24	1	2.5	8.4	5.1
26	1	8.3	9.8	5.1
28	1	3.3	20.5	13.5
29	1	1.0	15.4	8.4
21	2	6.5	12.1	8.7
22	2	7.5	16.6	9.7
23	2	4.0	11.7	5.1
24	2	4.0	8.4	5.1
26	2	9.0	9.8	5.1
28	2	6.3	20.5	13.5
29	2	3.0	15.4	8.4

The purpose of this exercise was to develop a quick and easy method of estimating either particulate loading or combustible loading from stoker fired boilers. It is observed in Figures 6-4 and 6-5 that no correlation can be made.

Based on this data, the modified smoke spot technique is not a viable method for estimating particulate or combustible loadings at the boiler outlet of spreader stokers. A primary reason is its inability to collect on filter paper the large particles which contain the majority of the particulate and combustible mass.

6.5 Corrosion Probe Study

A corrosion probe was installed in the convective section of Boiler A. This device is intended to give comparative information between different coals on the same boiler and between similar boilers burning the same coal. It does not give absolute boiler corrosion/erosion rates.

Table 6-4 summarizes the corrosion rate data and indicates which coals were burned during the residence of each coupon in the boiler. Kemmerer coal appears to be more corrosive than Stansbury coal after one month of exposure. Consolidation coal which was very low in sulfur could not be tested because it was only burned for a one-week period. Figure 6-6 shows the corrosion rate in mils/year as a function of cumulative time in the furnace. Again, Kemmerer coal appears to be more corrosive than Stansbury. However, scatter in the data prevents drawing quantitative conclusions.

The mechanism most often attributed to corrosion is the formation of ferric sulfide on the boiler tube surfaces. Thus, iron and sulfur are important fuel properties to examine. Sodium in the ash may also contribute to corrosion because it causes deposits to stick to the tubes. A correlation of coal properties with corrosion rate will be attempted when more data is available.

The corrosion rate appears to start out high and then decrease with time. Even after two months, it does not appear to have leveled off. The overall average corrosion rate was 3.2 mils/year, yet the rate for the two coupons which were exposed for the longest period of time averaged only 1.0 mils/year. The effect of this phenomenon on our ability to draw meaningful conclusions about long range corrosion potential is not known at this time.

TABLE 6-4

CORROSION RATE DATA

Coupon Number	Time in Boiler years	Weight Loss mg.	Corrosion Rate mils/year	Coals Burned
19	0.038	34.6	4.1	100% Stansbury
22	0.038	1.1	0.1	
27	0.090	98.9	5.0	100% Kemmerer
29	0.090	199.4	10.1	
21	0.099	63.5	2.9	50% Stansbury
23	0.099	71.9	3.3	50% Kemmerer
20	0.156	33.5	1.0	95% Kemmerer
25	0.156	108.0	3.1	5% Stansbury
24	0.195	73.6	1.7	75% Kemmerer
26	0.195	12.9	0.3	25% Stansbury

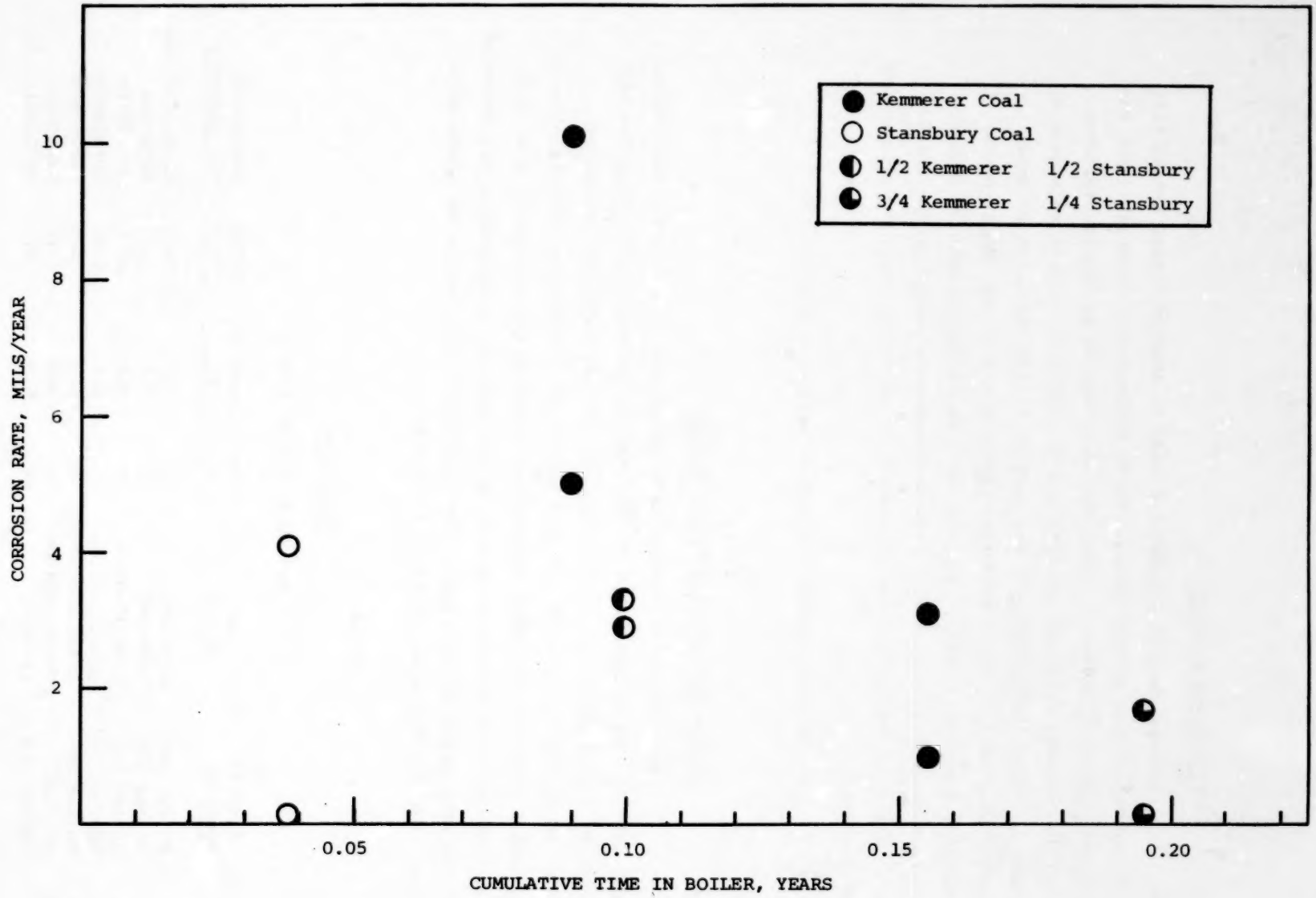


FIGURE 6-6. CORROSION RATE VS TIME

KVB 15900-521

6.6 Flyash Resistivity

An unsuccessful attempt was made to measure flyash resistivity with the Wahlco resistivity probe. Three factors were responsible for the problems with this device. First, the dust loading at the precipitator inlet (mechanical collector outlet) was too light to collect an adequate sample. Second, the sample cup was made of Teflon which has an upper temperature limit of 450°F. The gas temperatures at our sample point sometimes approached 500°F. The cup was damaged during testing because of the high temperature. Third, the device became coated on the outside with soot which caused the two electrodes to short out and give erroneously low readings.

No data was obtained from this device at Test Site A.

6.7 Source Assessment Sampling System

Seven Source Assessment Sampling System (SASS) tests were run at Test Site A. Three tests were run to satisfy the requirement that two SASS tests be run on the first coal tested and one for each coal thereafter. Three additional tests were run as a result of a joint test venture with the Aerotherm Division of Acurex Corporation under an EPA contract. A seventh test was rejected because of a leak in the sampling system which was detected at the conclusion of that test. The conditions under which the seven SASS tests were run are shown in Table 6-5 below.

TABLE 6-5

SASS TESTS RUN AT SITE A

Test No.	Sample Location	Coal Origin	Load %	Excess O_2 %	O.F.A. "H_2O	Contractor For Analysis
27	Boiler Out	Kemmerer	81	4.2	6.0	AD Little, Inc.
32	Boiler Out	Kemmerer	83	5.2	11.5	Rejected
34A	Boiler Out	Consolidation	76	5.9	10.5	Aerotherm
34B	ESP Out	Consolidation	76	5.9	10.5	Aerotherm
35A	Boiler Out	Consolidation	76	6.0	5.5	Aerotherm
35B	ESP Out	Consolidation	76	6.0	5.5	Aerotherm
40	Boiler Out	Kemmerer	66	6.9	5.5	AD Little, Inc.

POM, the total POM as percent of particulates will be reported. The identity and quantity of the following POM will be determined.

7, 12 - Dimethylbenz (a) anthracene
Dibenz (a,h) anthracene
Benzo (c) phenanthrene
3-Methylocholanthrene
Benzo (a) pyrene
Dibenzo (a,h) pyrene
Dibenzo (a,i) pyrene
Dibenzo (c,g) carbazole

APPENDIX A-1

HEATING VALUE OF FLYASH COMBUSTIBLES

Most flyash samples collected were analyzed for percent combustibles only. In order to assign a heating value to the combustibles it was necessary to determine their relative fractions of volatiles and fixed carbon.

To do this, four flyash samples from the boiler outlet were analyzed for percent volatiles and percent fixed carbon using ASTM methods D3172-75. The results are tabulated below:

Sample #	% Vol.	% Ash	% F.C.	% Comb.	Heating Value of Comb.
A	1.9	61.2	36.9	38.8	14358
B	0.7	65.5	33.8	34.5	14201
C	1.0	47.1	51.9	52.9	14196
D	0.9	60.0	39.1	40.0	14217
				Average	14243

The heating value of fixed carbon (FC) is taken as 14093 BTU/lb. We assume the volatiles to be similar to a #2 fuel oil having a heating value of 19500 BTU/lb. Thus, the average heating value for combustibles in these samples is 14243 BTU/lb with a standard deviation of $\pm$77 BTU/lb.

Based on these four tests the value 14250 BTU/lb has been assigned to all combustibles measurements for heat loss calculations.

APPENDIX A-2

ENGLISH AND METRIC UNITS TO SI UNITS

To Convert From	To	Multiply By
in	cm	2.540
in^2	cm^2	6.452
ft	m	0.3048
ft^2	m^2	0.09290
ft^3	m^3	0.02832
lb	Kg	0.4536
lb/hr	Mg/s	0.1260
$lb/10^6$BTU	ng/J	430
g/Mcal	ng/J	239
BTU	J	1054
BTU/lb	J/kg	0.002324
BTU/hr	W	0.2929
J/sec	W	1.000
J/hr	W	3600
BTU/ft/hr	W/m	0.9609
BTU/ft/hr	J/hr/m	3459
$BTU/ft^2/hr$	W/m^2	3.152
$BTU/ft^2/hr$	$J/hr/m^2$	11349
$BTU/ft^3/hr$	W/m^3	10.34
$BTU/ft^3/hr$	$J/hr/m^3$	37234
psia	Pa	6895
$"H_2O$	Pa	249.1
Rankine	Celsius	C = 5/9R-273
Fahrenheit	Celsius	C = 5/9(F-32)
Celsius	Kelvin	K = C+273
Rankine	Kelvin	K = 5/9R

COAL FUEL ONLY

ppm @ 3% O_2 (SO_2)	ng/J	0.851
ppm @ 3% O_2 (SO_3)	ng/J	1.063
ppm @ 3% O_2 (NO)	ng/J	0.399
ppm @ 3% O_2 (NO_2)	ng/J	0.611
ppm @ 3% O_2 (CO)	ng/J	0.372
ppm @ 3% O_2 (CH_4)	ng/J	0.213

APPENDIX A-3

SI UNITS TO ENGLISH AND METRIC UNITS

To Convert From	TO	Multiply By
cm	in	0.3937
cm^2	in^2	0.1550
m	ft	3.281
m^2	ft^2	10.764
m^3	ft^3	35.315
Kg	lb	2.205
Mg/s	lb/hr	7.937
ng/J	$lb/10^6BTU$	0.00233
ng/J	g/Mcal	0.00418
J	BTU	0.000948
J/kg	BTU/lb	4.303
J/hr/m	BTU/ft/hr	0.000289
$J/hr/m^2$	$BTU/ft^2/hr$	0.0000881
$J/hr/m^3$	$BTU/ft^3/hr$	0.0000269
W	BTU/hr	3.414
W	J/hr	0.000278
W/m	BTU/ft/hr	1.041
W/m^2	$BTU/ft^2/hr$	0.317
W/m^3	$BTU/ft^3/hr$	0.0967
Pa	psia	0.000145
Pa	$"H_2O$	0.004014
Kelvin	Fahrenheit	F = 1.8K-460
Celsius	Fahrenheit	F = 1.8C+32
Fahrenheit	Rankine	R = F+460
Kelvin	Rankine	R = 1.8K

COAL FUEL ONLY

ng/J	ppm @ 3% O_2 (SO_2)	1.18
ng/J	ppm @ 3% O_2 (SO_3)	0.941
ng/J	ppm @ 3% O_2 (NO)	2.51
ng/J	ppm @ 3% O_2 (NO_2)	1.64
ng/J	ppm @ 3% O_2 (CO)	2.69
ng/J	ppm @ 3% O_2 (CH_4)	4.69

APPENDIX A-4

SI PREFIXES

Multiplication Factor	Prefix	SI Symbol
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto*	h
10^{1}	deka*	da
10^{-1}	deci*	d
10^{-2}	centi*	c
10^{-3}	milli	m
10^{-6}	micro	μ
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

*Not recommended but occasionally used

APPENDIX A-5

EMISSIONS UNITS CONVERSION FACTORS
FOR TYPICAL COAL FUEL (HV = 13,320 BTU/LB)

To Obtain / Multiply by		% Weight In Fuel		lbs/10^6 Btu		grams/10^6 Cal		PPM (Dry @ 3% O_2)		grains/SCF (Dry @ 12% CO_2)	
		S	N	SO_2	NO_2	SO_2	NO_2	SOx	NOx	SO_2	NO_2
% Weight In Fuel	S	1		0.666		0.370		13.2×10^{-4}		1.48	
	N				0.405		0.225		5.76×10^{-4}		.903
lbs/10^6 Btu	SO_2	1.50		1		(.556)		19.8×10^{-4}		(2.23)	
	NO_2		2.47				(.556)		14.2×10^{-4}		(2.23)
grams/10^6 Cal	SO_2	2.70		(1.8)		1		35.6×10^{-4}		(4.01)	
	NO_2		4.44		(1.8)				25.6×10^{-4}		(4.01)
PPM (Dry @ 3% O_2)	SOx	758		505		281		1		1127	
	NOx		1736		704		391				1566
grains/SCF (Dry @ 12% CO_2)	SO_2	.676		(.448)		(.249)		8.87×10^{-4}		1	
	NO_2		1.11		(.448)		(.249)		6.39×10^{-4}		

NOTE: 1. Values in parenthesis can be used for all flue gas constituents such as oxides of carbon, oxides of nitrogen, oxides of sulfur, hydrocarbons, particulates, etc.

2. Standard reference temperature of 530°R was used.

KVB 15900-521